On the Way to Efficiently Supplying More Than Half of Turkey's Electricity from Renewables:

Costs and Benefits of Options to Increase System Flexibility

SHURA Energy Transition Center

About SHURA Energy Transition Center

SHURA Energy Transition Center, founded by the European Climate Foundation (ECF), Agora Energiewende and Istanbul Policy Center (IPC) at Sabancı University, contributes to decarbonisation of the energy sector via an innovative energy transition platform. It caters to the need for a sustainable and broadly recognized platform for discussions on technological, economic, and policy aspects of Turkey's energy sector. SHURA supports the debate on the transition to a low-carbon energy system through energy efficiency and renewable energy by using fact-based analysis and the best available data. Taking into account all relevant perspectives by a multitude of stakeholders, it contributes to an enhanced understanding of the economic potential, technical feasibility, and the relevant policy tools for this transition.

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ABBREVIATIONS

ADR	annual discount rate
BM	balancing market
CAES	compressed air energy storage
DAM	day-ahead market
EPDK	Enerji Piyasaları Düzenleme Kurumu
EPİAŞ	Enerji Piyasaları İşletme A.Ş.
ETKB	Enerji ve Tabii Kaynaklar Bakanlığı
EÜAŞ	Elektrik Üretim A.Ş.
EV	electric vehicles
GW	gigawatt
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JICA	Japan International Cooperation Agency
kg	kilogram
KV	kilovolt
LCOE	levelised cost of energy
LFP	lithium iron phosphate
Li-ion	lithium-ion
LTO	lithium titanate oxide
MCP	market clearing price
MW	megawatt
MWh	megawatt-hour
NCA	nickel cobalt aluminium oxide
NMC	nickel manganese cobalt oxide
OECD	Organisation for Economic Co-operation and Development
Op. Vost	operation costs
PV	photovoltaic
SRMC	short-run marginal cost
TEİAŞ	Türkiye Elektrik İletim A.Ş
TWh	terawatt-hour
TYNDP	Ten-Year Network Development Plan
VRB	vanadium redox batteries
VRE	variable renewable energy
VRLA	valve regulated

Executive Summary

Turkey's potential to supply half of its electricity demand from renewable energy sources by 2026

By the end of 2018, in total more than 5 gigawatts (GW) of solar photovoltaic (PV) and around 7 GW onshore wind capacity have been installed in Turkey, representing around 14% of Turkey's total installed electricity generation capacity. The combined electricity generation from solar PV and onshore wind supplied just below 10% of Turkey's total annual demand for electricity in 2018.

Recent analysis shows that the high-voltage transmission grid (including and above 154 kilovolts, kV) can integrate a total installed wind and solar capacity of 40 GW by 2026 without any operational difficulties or further grid investments beyond that has been planned by the transmission system operator (Türkiye Elektrik İletim A.Ş., TEİAŞ). This was shown by SHURA's grid integration study released in May 2018 (Godron et al., 2018). In such a scenario, more than 20% of Turkey's total annual electricity demand can be supplied from wind and solar by 2026, i.e. twice as high as the current target (*Doubling Scenario*).

The same study by SHURA shows that tripling the planned wind and solar capacity to 60 GW by 2026 (supplying 30% of Turkey's total electricity demand and half of the total demand including other renewables, *Tripling Scenario*) is possible, but integrating this capacity would require a more flexible power system, e.g. by introducing more flexible coal-fired power plants, demand response or energy storage. In addition, new wind and solar power plants would need to be relocated in areas where they can be integrated more easily. This is typically the case for localities where electricity demand is high and grid capacity is strong (*system-driven approach*). **Without increasing system flexibility, share of redispatch volumes would need to be nearly doubled with respect to the Base Case Scenario, and a share of the total renewable power would need to be curtailed, which would increase system costs subsequently.**

Flexibility options bring benefits at different orders of magnitude. These benefits were estimated and Turkey's power system was modelled with SHURA's power system tool developed by EPRA Enerji. The model has the capacity to simulate the power market and the transmission grid in Turkey to 2026 on an hourly basis, at the level of power plants (supply), electricity demand and down to line and substation levels of 154 kV and 400 kV grids. **Being the most attractive option available, the system-driven allocation of wind and solar capacity provides significant benefits to the system. These include a saving of 20% on additional grid investments by 2026 (equivalent to 100 million Euros per year), a reduction in redispatch volume from 7.8% of the total electricity output to 6.6%, and a reduction in total renewable power curtailment from 2.8% of total generation to 0.8%. Increasing system flexibility by a portfolio of options can reduce curtailment to 0.6% and redispatch levels to 3.1%.**

SHURA has prepared a series of papers to provide a path to reach this capacity target. The first paper in the series, titled "Balancing the Location of Wind and Solar PV Investments" (Saygin et al., 2018), was released in October 2018. A second paper in the series, titled "Opportunities to strengthen YEKA auction model for enhancing the regulatory framework of Turkey's power system transformation", provided a perspective on a future regulatory framework that employs renewable energy auctions (Sari et al., 2019). **This third and final paper that builds on SHURA's grid integration study estimates the costs and benefits of increasing system flexibility to derive the benefits mentioned above** by investigating the following options: energy storage enabled by (i) 600 megawatts (MW) of **distributed battery storage** (in total 11 battery storage technologies have been investigated mainly from electro-chemical and electro-mechanical types), (ii) 1.4 GW of **pumped-hydro storage**, (iii) **demand response mechanisms** that can shift load by 5% at any given time and (iv) **retrofitting old coal-fired power plants** to standard levels prevalent in Organisation for Economic Co-operation and Development (OECD) countries for increasing their flexibility by reducing the minimum generation level to 25%-40% and increasing ramp rates to 1.5%-4% of maximum generation per minute.

SHURA's comprehensive power system approach to estimate the costs and benefits of flexibility options

In the estimation of costs and benefits, SHURA's power system tool has been used based on the capacity mix assumed in SHURA's grid integration study. **In assessing the flexibility options, the focus was entirely on their impact on the weighted average short-run marginal cost (SRMC) (or the levelised cost of energy, LCOE, of the system) of the generation mix of the Tripling Scenario.** Evidently, Turkish economy can gain additional benefits from a more flexible power system that runs with higher shares of renewables such as a favourable trade balance that relies less on imported fossil fuels, new employment opportunities and diversification in economic activity. Such macroeconomic benefits, however, were excluded from the analysis carried out in this study.

The weighted average of the system LCOE of the generation mix in the Tripling Scenario was estimated at 37.85 Euro per megawatt-hour (MWh) in 2026. This compares with an estimate of 43.36 Euro/MWh in 2016. The reduction by around 5 Euro/MWh was due to an increasing share of zero marginal cost renewable energy sources of wind, solar and hydropower in the 2016-2026 period, from around 25% of the total demand to 45%. Each flexibility option has its own cost and economic benefit to the system, which were estimated in comparison to the weighted average SRMC of the generation mix in 2026. **As a starting point, it was assumed that the strategy to locate wind and solar capacity based on the system-driven approach was adopted. Subsequently, each flexibility technology was introduced seperately as an additional step to this strategy.**

Different options exist to increase system flexibility without excessive cost

The introduction of individual flexibility options reduce the required volume of redispatch by 2 terawatt-hours (TWh) and 10 TWh per year in 2026 depending on the option. This is equivalent to 8%-35% of the total redispatch volume required to integrate 60 GW wind and solar energy in the Tripling Scenario, which assumes system-friendly allocation of their capacity, but no flexibility option.

Costs of integrating wind and solar include several components, namely profile, grid and balancing costs, which increase as a functionof renewable energy penetration levels. Their total represent grid integration costs of solar and wind. Although balancing costs were excluded from the scope of this study, their share is generally much lower than the sum of profile and grid costs. Integration costs of solar and wind can be reduced by improving system flexibility. The analysis presented in this study mainly concerns the costs and benefits of such flexibility options. **The combined additional cost of the portfolio of selected flexibility options ranges from as low as 1.7 Euro to as high as 3.4 Euro per MWh, i.e. equivalent to 4.5%-8.9% of the weighted average of SRMC in 2026. Adding up the benefits of each option was not possible as the combined benefit would be lower than the sum of individual benefits, which was calculated between 1.3 Euro and 1.5 Euro per MWh, equivalent to 3.5%-4.0% of the weighted average of SMRC. The costs and benefits of flexibility options presented here fall within an uncertain range of ±20%** for the following reasons: despite promising developments, the future course of battery storage costs is highly uncertain as it is based on how the total global capacity will evolve and as reductions would need to mainly be derived from advancements to increase energy density, reduce cost and extend lifetime and the use of other materials for purposes like cell connectivity. Regarding demand response, it is assumed in this study that there is a readily available no-cost potential from the manufacturing industry and with rapid digitalisation of the economy, smart buildings will evolve in the near future; cost of pumped-hydro storage is specific to the selected terrain and even terrain details are known to project design; there are uncertainties with respect to the technology type, flexibility level and age of power plants that will be retroffited, and in relation to the extent that proposed flexibility measures can be implemented.

The cost and benefit of each flexibility option is discussed below:

- **Retrofitting old coal-fired power plants** to increase their flexibility requires an additional cost of 0.71 Euro/MWh, with the largest benefit among all options estimated at 0.50 Euro/MWh, implying a net cost of 0.55% of the weighted average of SMRC. The main reason for high benefits is the faster response of these units to changes and their increased secondary control reserve capability. The latter allows coal plants to partially substitute gas plants for reserve capacity, thereby reducing reserve costs.
- **Demand response** results in net benefits of 0.4% from an estimated absolute benefit of 0.15 Euro/MWh and no additional investment costs. In comparison to other technologies, however, it has the lowest benefits, estimated at around 0.15 Euro/MWh. The high cost for utilisation of demand response, which is also observable from available practices such as the active contribution in Belgium, France and Republic of Korea, results in the activation of this option as a last resort, only if redispatch is not resolved after all flexibility options are introduced. Furthermore, the amount of demand response is assumed to be limited to 5% of the load in each substation. Even though the assumed 5% of hourly load results in a substantial capacity, application in the model is rather low due to high utilisation cost of demand response, which practically limits the effectiveness of this option to relatively low levels.
- **Energy storage,** on the other hand, is used both for frequency control and energy shifting: half of the total 600 MW battery storage capacity is assumed to be operated for frequency control reserve and the other half would be available for energy shifting. Investment and annual operation costs of both schemes are considered in the calculations separately. 100 MW of each of the four equal units of 1.4 GW of total pumped-hydro storage capacity is allocated for frequency control reserve, leaving 1 GW for energy shifting. Depending on the technology, battery storage increases the weighted average SRMC of the capacity mix between 0.7 Euro and 2.1 Euro per

MWh. Benefits from reduced redispatch, curtailment and capacity requirements from conventional units amount to 0.27 Euro and 0.45 Euro per MWh. High temperature and Li-ion batteries provide the highest benefits. These benefits rank second after the retrofitting of old coal-fired power plants. For the specific case of pumped-hydro storage, our estimates indicated a net cost of 0 Euro/MWh, since its cost of 0.4 Euro/MWh equals the benefits.

Policy mechanisms that consider different requirements of flexibility options as well as a market design that allows competition to arrive at the cost-optimum system flexibility are needed

The role of battery storage is being discussed for several years in Turkey. At the end of January 2019, a draft legislation on energy storage was released for public consultation. In addition, energy companies are looking into options for investing in battery storage technologies and related business models to operate them. While the issue is attracting much interest, there is a need to better understand in which areas should investments be directed, to what extent should storage capacity be built, which technology should be employed for which purpose, and when does battery storage makes the most economic sense. **The results of this study show that a total distributed battery storage capacity of 600 MW would be an important source of flexibility to integrate 30% share of wind and solar energy into the system. However, such capacity may not be necessarily needed to integrate a wind and solar share of 20%, because TEİAŞ's existing grid planning would be sufficient for wind and solar integration at this level.** This is an outcome of the benefits that follow a nonlinear function of solar and wind share: as the share of renewable energy increases, the benefits from these options also increase compared to the case without flexibility.

Based on the findings of this study, the following conclusions are drawn:

- **Demand response does not require large specific investments, which makes it an interesting flexibility option.** However, activation cost is high, which implies that it is utilised in the model only when other options are exhausted. More importantly, in order to allow consumers to participate in demand response management of manufacturing industry and the building stock electricity demand, installation, operation and planning for the use of supporting infrastructure such as smart meters, sensors, control systems are required. Therefore, **a holistic policy approach is needed for the integration of the power sector with electricity consuming end-use sectors. The large electrical load due to steel production in electric arc furnaces and cement grinding can serve as a starting point for demand response since the load in such plants can be more easily shifted and controlled.**
- **The pumped-hydro storage capacity can be one of the most attractive flexibility options with installed capacities offering a long lifetime of operation.** Considering a long-term vision with increasing levels of wind and solar energy over time, pumped-hydro storage can be a strategically beneficial decision for the power system. Such long-term vision would also allow improving the cost-effectiveness of the system in the long run for grid integration of renewables.
- **Battery storage systems can provide flexibility, but the initial capital costs of most technologies are still too high compared to the benefits they bring to the system.** Thus, the required storage capacity should be planned in conjunction with large shares of wind and solar capacity to minimise additional system costs

and to bring the most benefits where needed. **One possible way forward for the deployment of these systems is to start with smaller scale installations, provide niche services and complement other flexibility options.**

- **Retrofitting old coal-fired plants is estimated to have the largest benefits.** In a power system with high shares of solar and wind, the capacity factors of coal-fired power plants drop significantly, impacting their profitability. If flexibility requirements are adequately reflected in the (short-term) markets, increasing flexibility would allow coal-fired power plants to provide electricity also in times of high ramps and low residual demand from non-renewable generation, which otherwise would be provided by gas-fired power plants fuelled by imported gas. **From a public policy perspective, however, climate impacts of such a development should also be considered. Equally important, Turkey's lignite with low-energy content provide opportunity only for some extend flexible generators.** Thus, technically there will be limited electricity generation capacity where flexibility can be improved (around 9 GW by 2026 as estimated in this study).

Beyond the regular operation of the power system, which is the main focus of the study considering security and reliability, power systems are also expected to maintain their operational abilities under extreme conditions referred to as resiliency. Essentially, resilience of any power system is increased with higher rates of flexibility brought by a variety of system benefits. While these could not be assessed in this study, in emergency situations, system operators would benefit from fast-responding generation, storage and demand, which would help avoiding brownouts and blackouts. **There are also macroeconomic benefits of a more renewable and flexible power system that are not quantified here such as reduced reliance on fossil fuel imports, new economic activity and employment creation. It is also important to put such benefits into perspective while designing strategies and policies for transition to a low-carbon energy system in Turkey.**

Based on the findings of this study, the following five recommendations are identified for consideration of energy planners, grid operators, market regulators and the energy industry of Turkey:

1. Develop a **comprehensive grid integration plan** for wind and solar based on a geographically elaborated strategy to balance supply and demand and by increasing system flexibility.
2. Create a **regulatory framework** and develop **supporting policy mechanisms that reflect the value of flexibility** to provide adequate incentives for making use of available flexibility options and investing in new ones. In this respect, the essential instruments are transparent short-term and balancing markets.
3. Implement **early opportunities with low cost** which can provide rapid response ability for increasing system flexibility requirements.
4. Identify and overcome **barriers related to demand response** given its attractiveness.
5. Develop a plan for **battery storage** by analysing **its value and role** for different technologies **at stages of higher wind and solar shares** in detail.

1. Introduction

Transformation of the power system with higher shares of wind and solar energy runs into several operational challenges as the electricity generation from these technologies are variable and uncertain. All around the world, system operators are trying to adapt to changing conditions of the power system with higher shares of wind and solar energy. Such adaptation requires the system to be flexible so as to integrate variable renewable energy (VRE) sources of wind and solar. Options to increase system flexibility include strong transmission grids, flexible generators, interconnector capacity that allows electricity trade with neighbouring countries, demand-side management strategies, energy storage, and improved techniques for energy planning and forecasting. Their implementation, however, are specific to the country conditions as outlined in the SHURA Energy Transition Center's recent review of country-specific experiences (Saygın and Godron, 2018) (see also IEA,2018a).

Turkey's electricity system is characterised by large demand centres located in the western regions of the country driven by large industrial and economic activity as well as seasonal agricultural demand in the southeast region (Godron et al., 2018). Supply of electricity is based on hydropower in the east, on gas-fired generation in the west and on coal in specific areas across the country's entire geography. This partial imbalance between regional supply and demand results in high congestion of the transmission grids from the east to the west. This imbalance may grow with increasing capacity of wind and solar, as resources and land availability are not evenly distributed across the country. Congestions will particularly increase in the south-west corridor as best available solar resources are in the south. This will particularly be the case if the total installed capacity of wind and solar energy reaches 60 gigawatt (GW), triple the value of the capacity according to the transmission system operator's plan for 2026 as indicated in the grid integration study undertaken by SHURA (Godron et al., 2018). This capacity along with other renewables would provide half of all Turkey's electricity demand by the same year, but to relieve grid congestions and ensure the secure and reliable operation of the electricity grid, the transmission system operator must deploy several options in hand: curtailment of renewable power, increase redispatch amounts and introduce options to increase system flexibility. None of these options come for free. For instance, the same study by SHURA shows that total curtailment of electricity generated from wind and solar would represent 3% of their total output, indicating that a considerable share of the output would be wasted. A system-driven approach to locate this capacity to areas with stronger grids and higher demand would resolve curtailment to reduce its share below 1%, besides providing 20% saving on additional grid investments until 2026, but the levelised cost of electricity generation of the power plants that are relocated would increase by around 10% (Saygin et al., 2018). Other options that are needed to ensure system security and reliability are distributed battery storage, pumped-hydro storage, demand response and retrofitting old coal-fired power plant to increase their flexibility (Godron et al., 2018).

Energy planners and system operators need to have clear insight into costs associated with flexibility options and the economic and technical benefits they offer.

Energy planners and system operators need to have clear insight into costs associated with flexibility options and the economic and technical benefits they offer. Building on the grid integration study that was developed by SHURA for the period between 2016 and 2026 (Godron et al., 2018), this study quantifies and compares the costs and benefits associated with each one of these options to increase system flexibility. This analysis investigates the costs and benefits of these options for a scenario where 60 GW of wind and solar energy capacity is implemented (this total is split equally between wind and solar, hence each are assumed to have 30 GW capacity), the so-called Tripling Scenario. The rest of this report is organised as follows: section 2 provides insights into the methodology. In section 3, the costs and benefits of each flexibility option are provided. These are compared with each other in section 4. The last section of the report offers recommendations to energy planners, the transmission system operator and energy companies.

Box 1: Challenges in different phases of renewable energy integration

It is important to understand the challenges of grid integration, at which phase of variable renewable energy penetration they could pose a threat to the power system and what type of measures are needed to overcome these challenges. This is essential for the planning of Turkey's power system transformation. The International Energy Agency (IEA) (IEA, 2018a; 2017) outlines three principal characteristics of the power system that determine the extent of challenges related to the grid integration of renewables, namely structural and technical factors, system operation, market design and regulation, and the fundamentals of supply and demand.

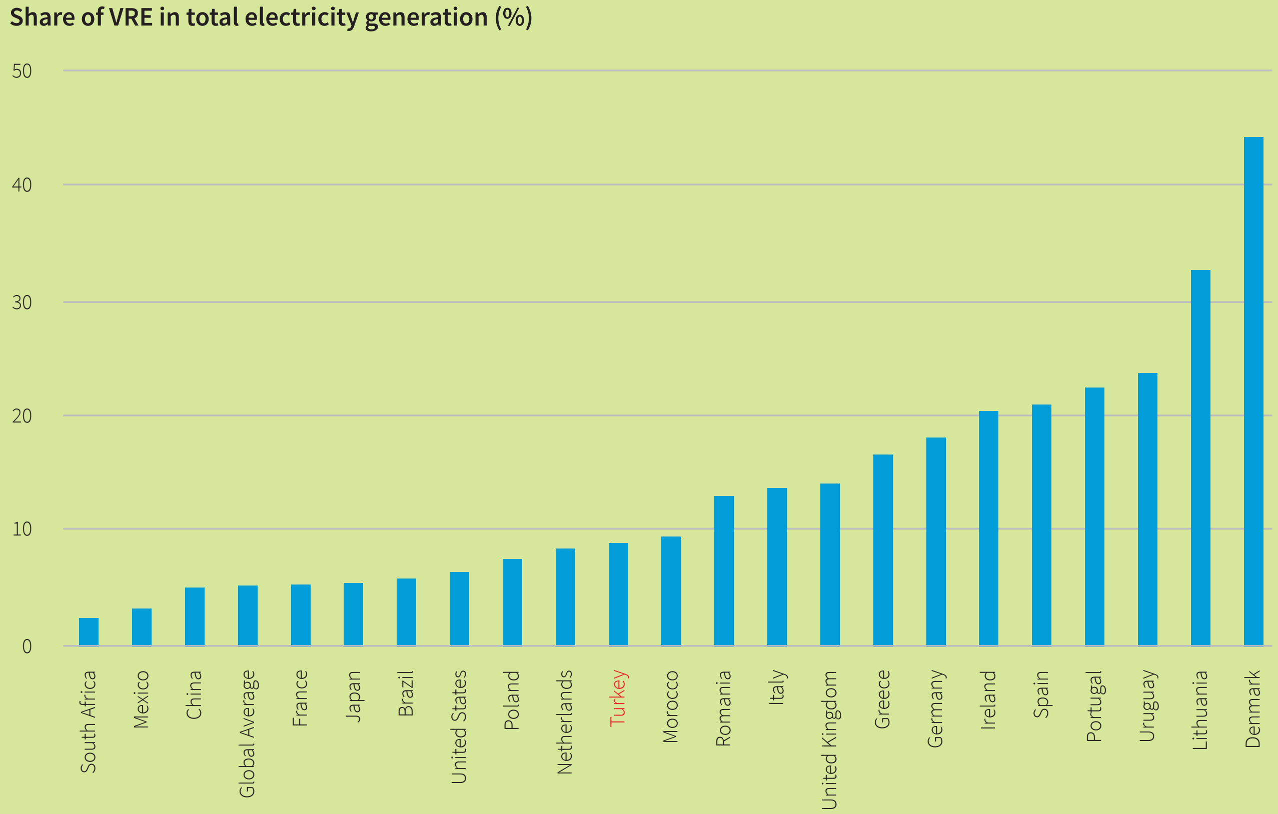
Structural and technical factors play a crucial role. The geographical spread of VRE capacity is important since more diverse location of generators reduces challenges. The size of demand also matters since larger systems are more resilient. Good matching electricity demand with the output from variable renewable energy systems means fewer challenges. A more flexible system enabled by storage, interconnector capacity, demand response and thermal power plants makes grid integration of renewables more manageable. Real-time operation of power plants and interconnectors, short-term trading of electricity and implementation of grid codes are equally important market, regulatory and operational aspects that need to be addressed to reduce grid integration challenges (IEA, 2018a).

The same report by the IEA (2018a) categorises these challenges into 6 phases of grid integration of renewables:
- Phase 1: VRE has no noticeable impact on system operation
- Phase 2: VRE has a minor to moderate impact on system operation (challenge: minor changes to operating patterns)
- Phase 3: VRE generation determines the operation pattern of the system (challenge: greater variability of net load and new power flow patterns)
- Phase 4: The system experiences periods where VRE makes up almost all generation (challenge: power supply robustness under high VRE generation)
- Phase 5: Growing amounts of VRE surplus (days to weeks) (challenge: longer periods of energy surplus or deficit)
- Phase 6: Monthly or seasonal surplus or deficit of VRE supply (challenge: need for seasonal storage)

As the share of VRE in the power system increases, these technical, operational, market and regulatory challenges will need to be addressed. This study investigates the costs and benefits of technical options that can help to increase system flexibility and reduce costs related to grid integration of wind and solar.

End of 2018, Turkey's VRE share stood at around 9% of the total generation. This share has been increasing by 1-to-2 percentage points each year as Turkey adds more solar and wind capacity. Based on today's VRE share, like many other countries, Turkey's integration challenge can be placed in Phase 2. Only a handful of countries like Ireland, Spain and Denmark are experiencing Phase 4 challenges, where their systems require advanced technologies to ensure system reliability. Germany, Italy and the United Kingdom can be considered in Phase 3 where flexibility investments are needed. Increasing the share of wind and solar energy to 30% by 2026 as estimated in SHURA's grid integration study would place Turkey in between Phases 3 and 4.

Figure 1: *Share of solar and wind power in total electricity generation, 2016*



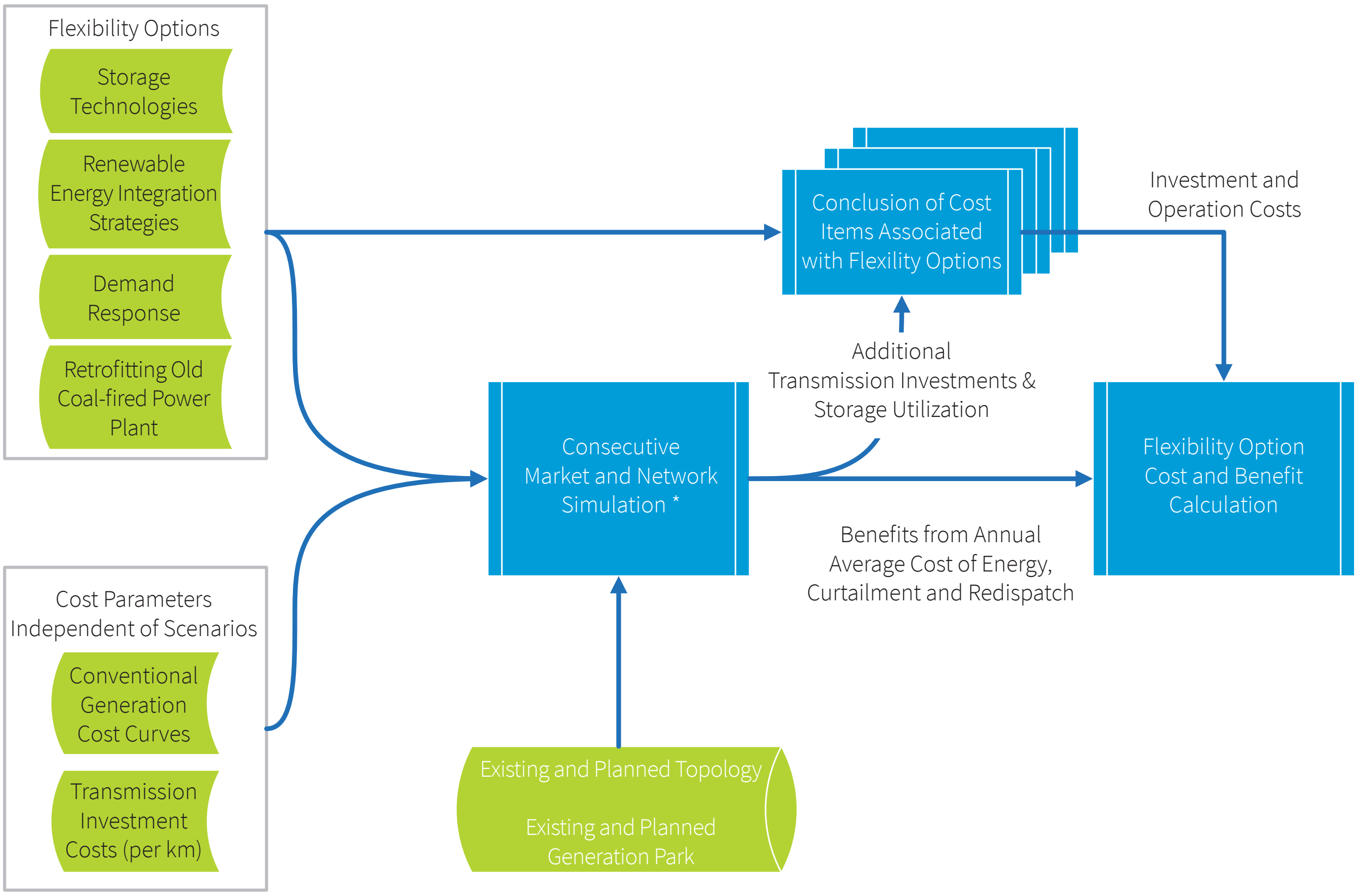
Source: (IEA, 2018b), and authors' estimates. Note: Turkey data is for 2018.

2. Methodology

The analysis is based on the modelling of different flexibility options and a market and network simulation to determine the impact of individual as well as combined costs and benefits of flexibility options on the short-run marginal costs of electricity.

In this section, the general approach adopted to estimate the costs and benefits of each flexibility option is explained. The analysis is based on the modelling of different flexibility options and a market and network simulation (Market Operator and the National Dispatch Centre) to determine the impact of individual as well as combined costs and benefits of flexibility options on the short-run marginal costs of electricity. The flowchart of the methodology applied in this study is shown in Figure 2. There are three main input sets: existing and planned generation/transmission components, cost parameters independent of the scenario, and finally, cost parameters of each flexibility option. These three data sets drive two main calculation algorithms: consecutive market and network simulation, and an external calculation of costs associated with investments for and operation of flexibility options as well as the costs of transmission investments. The general summary of input data and the utilised calculations are summarised in Table 1.

Figure 2: *General flowchart of the methodology*



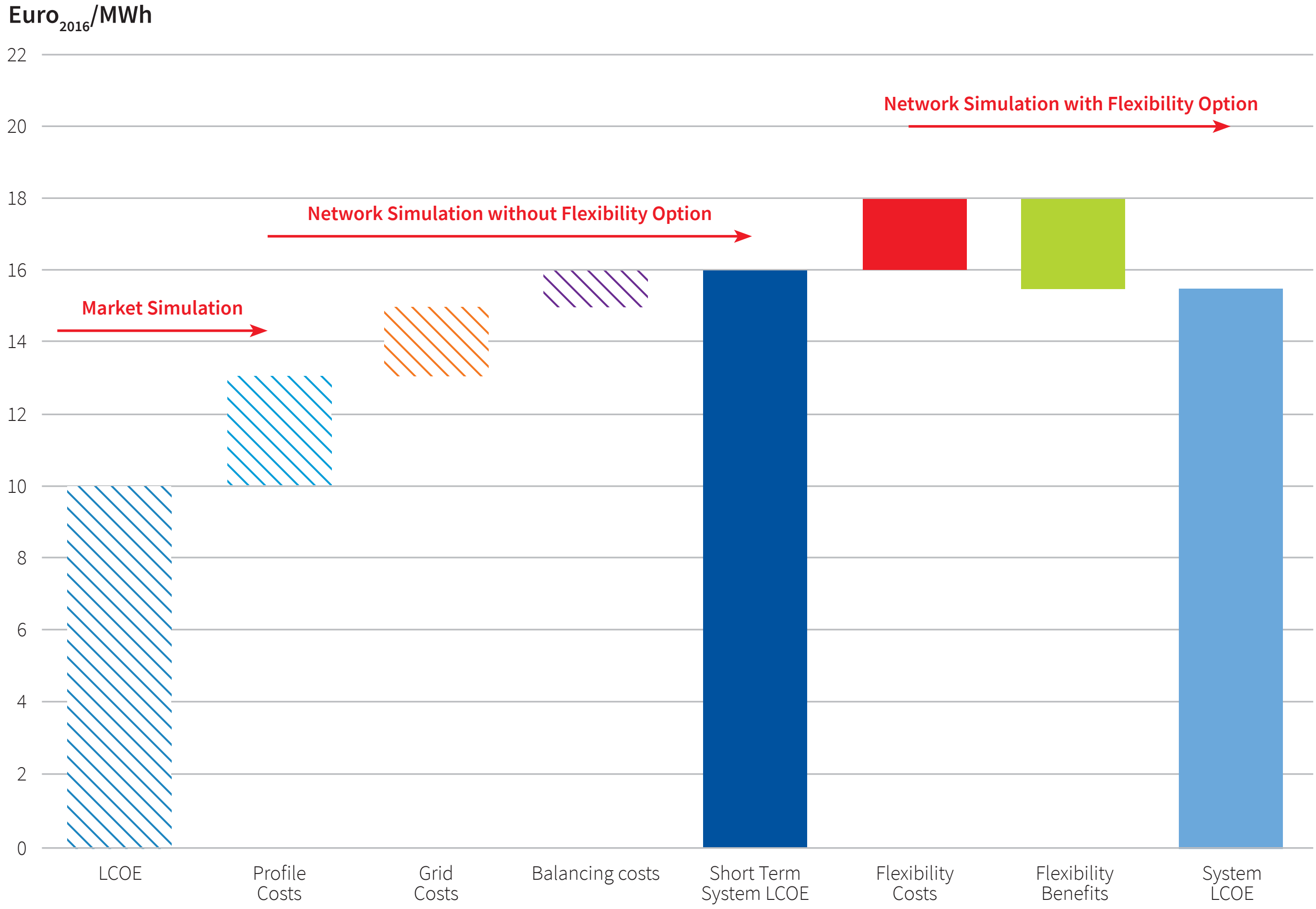
Note: (*) see Figure 12 for details.

The costs estimated in this analysis provide a first step toward understanding the full costs of integrating renewables into the grid. According to the OECD and NEA (2019) integration costs are the sum of profile costs, grid costs and balancing costs (where their sum represent the short-term integration costs of wind and solar) minus benefits from flexibility options. In this analysis, only profile costs and grid costs are estimated. Balancing costs are assumed to be zero as there is a perfect match between

Grid integration costs include: profile, grid and balancing cost.

forecasted and real generation. Therefore the remaining balancing cost components together with the connection costs[1] are excluded, even though they may have an impact on the findings. Utilising a similar approach with the OECD and NEA (2019), the evaluated system costs are summarised as shown in Figure 3. The costs related to the levelised cost of electricity generation (LCOE) profile and grid costs are calculated, but not exclusively reported in the study. The magnitude of grid integration costs changes with higher penetration of wind and solar energy. Profile costs can rise to 15 Euro to 40 Euro per MWh for wind penetrations that reach to 30%-40% in different regions of the world (Ueckerdt et al., 2013). Costs related to balancing and grid are much less than profile costs. Balancing costs can range from zero to as high as 13 Euro/MWh for various penetration levels of wind and solar in different countries (Joos and Staffell, 2018). Grid costs range between 1 Euro and 7 Euro per MWh (Sjim, 2014). When these costs are added, grid integration of wind and solar can range from below 15 Euro to as high as 60 Euro per MWh, depending very much on the state of the overall system.[2] This analysis looks at the costs and benefits of flexibility options to reduce these grid integration costs. It is assumed that the generation capacity mix remains unchanged, thereby excluding the benefits that can be gained from an optimum capacity mix.

Figure 3: *Illustration of grid integration costs of wind and solar*



[1] Connection costs consist of the costs of connecting a power plant to the nearest connecting point of the transmission grid.
[2] It should be noted that there is disagreement among experts on whether the "profile cost" or "utilisation effect" can (and should) be considered as integration costs since new plants always modify the utilisation rate of existing plants, independently from their technology. When new solar and wind plants are added to a power system, they reduce the utilisation of the existing power plants, and thus their revenues. Therefore, when assessing the overall cost effect of larger shares of renewables on the system, one would need to make a complete cost analysis of optimised systems (Agora Energiewende, 2015).

The study covers a significant range of flexibility options, which are explained in detail in section 2.1. Essentially, various input parameters are defined to perform these analyses. The details of these input sets and assumptions related to costs associated with investment, operation and power generation are defined in section 2.2. Finally, the simulation approach (section 2.3) and levelisation of costs and benefits (section 2.4) are described.

Table 1: *General summary of input data and the calculations used*

Cost Type	System Components and Flexibility Cases	Representation in Simulation	Cost Components	Calculation of Installation Cost	Calculation of Operation/ Activation Cost
Independent of Scenario	**Retrofitting old coal-fired power plants**	Committable sources	Generation Cost Curves	Not applicable	Within market & network simulation
	Renewable Generation	Zero-cost dispatchable sources with hourly max generation constraints	Cost of Renewable Curtailment	Not considered	Within market & network simulation
	High-Voltage Transmission	Network topology and operation (dispatch orders for security and reliability)	Installation (new investments) and operation (redispatch) costs	Simulation and external calculation	Within market & network simulation
Individual Scenario Related	**Battery & Pumped-hydro Storage**	Storage systems	Installation and operation costs	External calculation	Simulation and external calculation
	Retrofitting old coal-fired power plants	Improved flexibility sources	Installation and operation costs	External calculation	Within market & network simulation
	Demand Response	High-cost dispatchable sources with hourly max generation constraints	Installation and operation costs	Considered as zero cost	Within market & network simulation

Notes: Simulation and external calculation: Based on the results of market and network simulations further calculations have been carried out.

Beyond the power system, demand response requires developments in the manufacturing industry and buildings, which are expected to prepare themselves for the challenge. One of the major concerns related to this topic is the roll out of smart meters. According to Frost and Sullivan (2017) electronic meters dominated the market with 86% share in 2016 and further increase is expected until 2020. Similarly, Turkish power sector is already undertaking the necessary major developments and investments in this direction. Hence, no further cost is considered for this item.

Box 2: Sources of flexibility

There are four main sources to increase system flexibility: power plants, grids, demand response and storage. Effective management of these sources and their operation require new regulatory frameworks and market design (IEA, 2018a; NREL, 2014). Depending on the phase a power system is in, each flexibility source comes with different options; for instance, ranging from simple power plant retrofits to advanced solutions like the use of synthetic fuels to generate electricity. Different flexibility options also address the different durations of variability in a power system from a few seconds to regulate frequency to months where seasonal arbitrage is needed. For example, battery storage can provide flexibility between seconds to minutes when connected either at distribution or transmission grids. Interconnectors provide load balancing in hours to days as a flexibility option providing service at the transmission level.

Table 2: *Sources of flexibility and the phase of VRE integration in which they address the flexibility issue*

<table>
<tr><th></th><th>Power plants</th><th>Grids</th><th>Demand response</th><th>Storage</th><th>Regulations and markets</th></tr>
<tr><td>Phase 6</td><td rowspan="2">Synthetic fuels for power generation</td><td rowspan="2">Large-scale networks to smooth seasonal variability</td><td rowspan="2">Tap new loads via electrification</td><td>Long-term storage</td><td></td></tr>
<tr><td>Phase 5</td><td>Medium-term storage</td><td>Re-evaluate electricity taxation</td></tr>
<tr><td>Phase 4</td><td>Advanced plant design</td><td>Digitalisation and smart grid technologies</td><td>Commercial and residential</td><td>Battery storage</td><td>Reform of system services markets</td></tr>
<tr><td>Phase 3</td><td>Flexibility from VRE</td><td rowspan="2">Grid reinforcement, interconnectors</td><td>Advanced large industrial</td><td>Use of existing storage, e.g. pumped-hydro</td><td>Effective short-term wholesale markets, trade with neighbours</td></tr>
<tr><td>Phase 2</td><td>Retrofit plants for flexibility</td><td></td><td></td><td rowspan="2">Improve VRE forecasting, economic dispatch</td></tr>
<tr><td>Phase 1</td><td></td><td></td><td></td><td></td></tr>
</table>

Source: IEA (2018a)

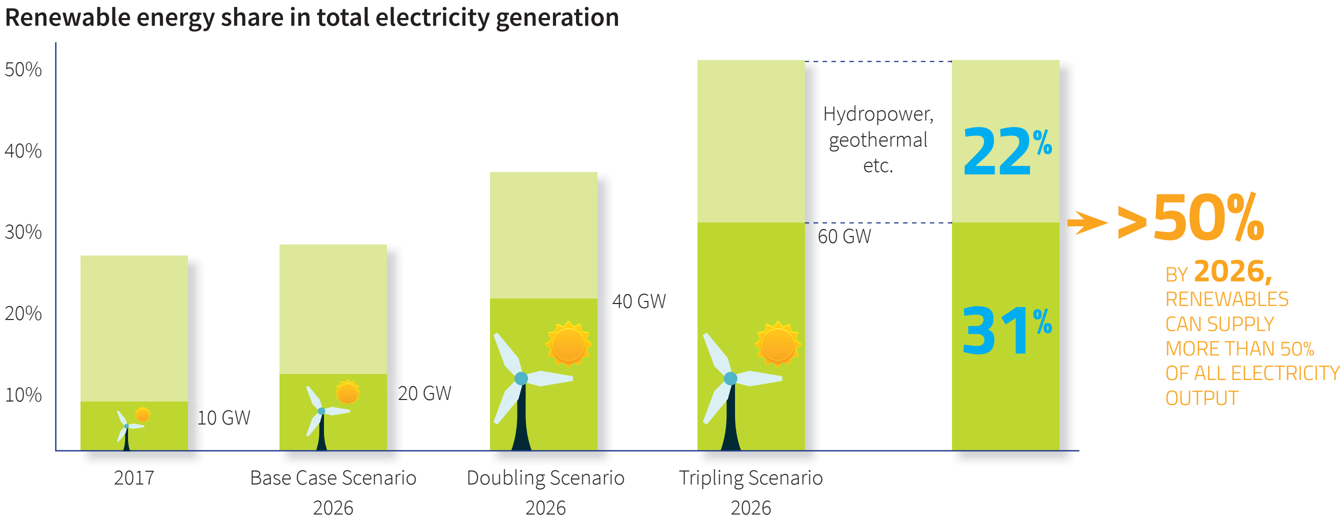
2.1 Investigated flexibility options

The grid integration study of SHURA (Godron et al., 2018; Saygin et al., 2018) investigated three distinct wind and solar deployment scenarios: the Base Case Scenario with a total of 20 GW wind and solar energy capacity which complies with Türkiye Elektrik İletim A.Ş. (TEİAŞ) Ten-Year Network Development Plan (TYNDP), the Doubling Scenario (40 GW wind and solar energy in total) and the Tripling Scenario (60 GW wind and solar energy in total) (see Figure 4). In the Doubling and Tripling Scenarios, considering Turkey's abundant resources, equal shares of wind and solar capacity were assumed.

The main outcome of SHURA's grid integration study was that the Doubling Scenario is achievable without major changes in grid planning and operation.[3] However, additional grid investments and significant amount of redispatch and renewable power curtailment would be needed for the Tripling Scenario, unless action is taken to increase system flexibility. This would eventually increase system LCOE and make grid operation more challenging.

[3] TEİAŞ argues that the reference year selected for comparison of results (2016) in SHURA's grid integration study was a difficult one from operational perspective due to continuing investments. After finalisation of these investments, the redispatch amounts were reduced. Hence, calculated redispatch amounts are beyond TEİAŞ expectations/intentions for year 2026 (target year of the analysis).

Figure 4: *Solar, wind and total renewable energy shares according to SHURA's grid integration study scenarios, 2017-2026*



Source: Godron et al. (2018) Saygın et al. (2018)

The introduction of five flexibility options can ensure the integration of 60 GW wind and solar capacity in order to supply more than 30% of Turkey's total electricity demand – when combined with the output from other renewables, half of total demand – by 2026. These options include system-driven approach to locate wind and solar capacity, energy storage with batteries and pumped-hydro storage, increasing thermal power plant flexibility through retrofits, and finally, demand response.

The same study also showed that the introduction of five flexibility options can ensure the integration of 60 GW wind and solar capacity in order to supply more than 30% of Turkey's total electricity demand – when combined with the output from other renewables, half of total demand – by 2026. These options include system-driven approach to locate wind and solar capacity (Saygin et al., 2018), energy storage with batteries and pumped-hydro storage, increasing thermal power plant flexibility through retrofits, and finally, demand response. Each flexibility option is briefly discussed below:

Energy storage (Joseph and Shahidehpour, 2006)

- Lead-Acid Batteries:
  - Flooded: Lead-acid batteries are marginally economic, but they impose substantial space and maintenance requirements. They also have a shorter life, which decreases rapidly if battery is discharged below 30%. This results in the reduction of energy density, which in turn leads to increased capital costs. Lead-acid batteries have several key limitations:
    - they require relatively frequent maintenance to replace the water lost during operation,
    - they are relatively expensive compared to conventional options with limited reduction in expected costs, and
    - since they contain lead, they are heavy, which in turn reduces their portability and increases construction costs.

    The major strengths of flooded lead-acid battery centres are their relatively long life span, durability, and the commercial availability of the technology. Even though this reduces their impact on system LCOE, limited discharge levels restrict the positive impact of these batteries.

  - Valve Regulated (VRLA): VRLAs use the same basic electrochemical technology as flooded lead-acid batteries, but these batteries are closed with a pressure regulating valve, so that they are essentially sealed. In addition, the acid electrolyte is immobilised. More frequent replacement of the battery subsystem may be needed with respect to flooded lead-acid batteries, increasing the system LCOE. The major advantages of VRLAs over flooded lead-acid cells are:

- the dramatic reduction in the maintenance necessary to keep the battery in operation, and
- the battery cells can be packaged more tightly because of the sealed construction and immobilised electrolyte, reducing their footprint and weight.

The disadvantages of VRLAs are that they are less robust than flooded lead-acid batteries, and they are more costly and shorter-lived. The short lifetime increases the impact on system LCOE and the limited discharge levels restrict the positive impact of these batteries.

The main advantage of Li-ion, compared to other advanced batteries, are their high energy density, high efficiency and long life-cycle.

- Lithium-ion (Li-ion) batteries: The main advantages of these batteries, compared to other advanced batteries, are their high energy density, high efficiency and long life-cycle. Even though Li-ion batteries have taken over 50% of small portable market in a few years, there are certain challenges in manufacturing large-scale Li-ion batteries. The main hurdle is the high cost due to special packaging and internal overcharge protection circuits. Several companies are working to reduce the manufacturing costs of Li-ion batteries to capture large energy markets. Four specific types of Li-ion technologies are investigated in the study, namely, lithium iron phosphate (LFP), lithium titanate oxide (LTO), nickel cobalt aluminium oxide (NCA) and nickel manganese cobalt oxide (NMC). While the high cost of these batteries influence the system LCOE negatively, their benefits are not enough to compansate these costs.

- Flow-based batteries: Two types of flow batteries are investigated in the study. Vanadium redox batteries (VRB) store energy by employing vanadium redox couples (V^{2+}/V^{3+} in the negative and V^{4+}/V^{5+} in the positive half cells). These are stored in mild sulfuric acid solutions (electrolytes). On the other hand, in each cell of a zinc (ZnBr) battery, two different electrolytes flow through carbon-plastic composite electrodes in two compartments separated by a microporous polyolefin membrane. In both technologies, power and energy ratings of the instalment can be defined independently, allowing the installation to be arranged according to the needs of the application. Since they are more cost-effective, the impact of flow-based batteries on system LCOE is less compared to the options mentioned above and their benefits are slightly higher.

- High-temperature batteries: These batteries consist of liquid (molten) materials at positive and negative electrodes as active materials separated by a solid beta alumina ceramic electrolyte. The electrolyte allows only the flow of positive sodium ions. The battery is kept at about 300 degrees C to allow this process. These battery cells are efficient and have a pulse power capability over six times their continuous rating (for 30 seconds). This attribute enables these batteries to be economically used in combined power quality and peak shaving applications. This battery technology has been demonstrated at over 30 sites in Japan with a total capacity more than 20 megawatts (MW) and stored energy suitable for 8 hours of daily peak shaving. The largest NaS installation is a 6 MW, 8h unit delivered by Tokyo Electric Power Company. In this study, two specific types are investigated: NaS and NaNiCl. The flexibility and relative longer lifetime of these batteries allows them to have less impact on system LCOE and higher benefits.

The pumped-hydro storage, a mature technology, has been in use since 1930s as a storage option.

- Mechanical Systems: Two types of applications, pumped-hydro storage and compressed air (CAES), are investigated. The pumped-hydro storage, a mature technology, has been in use since 1930s as a storage option. The first application of CAES was also realised in 1991 with 110 MW installed capacity. Although these sytems have very high instalment costs and are not as fast responding as batteries, they are still considerable flexibility options on the grid scale due to their long lifetimes and large bulk storage ability. Although these storage systems require significant investments, the increase of system LCOE is limited due to long lifetime. Hence, even though these systems increase the system LCOE, this is still less than any of the options mentioned above.

- Pumped-hydro storage: Pumped-hydro storage facilities store energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. During periods of high electricity demand, power is generated by releasing the stored water through turbines in the same manner as a conventional hydropower station. During periods of low demand (usually nights or weekends when electricity is also lower-cost), the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Retrofitting old coal-fired power plants

Older coal-fired power plants and many other thermal power plants developed for baseload operation provide limited operational flexibility. This is a question of design rather than whether they can actually be flexibly operated. These older plants have a large upside potential for retrofit measures to increase efficiency and flexibility. At the power plant level, operational flexibility is characterised by three main features: the overall bandwidth of operation (ranging between minimum and maximum load), the speed at which net power feed-in can be adjusted (ramp rate) and the time required to attain stable operation when starting up from standstill (start-up time). Numerous technical possibilities exist to increase the flexibility of these coal-fired power plants and these have been successfully implemented in several countries. Increasing flexibility would provide more options to TEİAŞ for addressing fast changes in the grid (Agora Energiewende, 2017).

The demand response is a concept that allows large industrial consumers or even small consumers like households to participate in the system operation by providing flexibility as a response to an available price signal or to activate a flexibility product.

Demand response

The demand response is a concept that allows large industrial consumers or even small consumers like households to participate in the system operation by providing flexibility as a response to an available price signal or to activate a flexibility product. Such services allow the operator to give orders to consumption when conventional redispatch orders are insufficient to relieve grid congestions. As seen from existing applications, these services require communication and availability of relevant equipment both on the system operator and the consumer side. In this study, demand response is considered as a flexibility option based on certain assumptions about the development of technology, digitalisation and load flexibility, which are defined in section 2.2.3.4.

In this analysis, the costs and benefits of each of these flexibility options are estimated. It should be noted that this paper focuses on a predefined electricity generation capacity mix and its impact on the system LCOE. This does not suggest by any means that the selected strategy/flexibility option and its application/distribution to the grid is optimum. In modelling each flexibility option, different assumptions were made concerning issues such as the selection of pumped-hydro storage location, the distribution of the battery storage systems to different high voltage substations or the plants to be retrofit. These assumptions are explained in more detail in SHURA's grid integration study (Godron et al., 2018).

Flexibility options become more important during times of higher shares of renewable energy penetration to the power system. The analysis focuses on the role of these options to the integration of 60 GW wind and solar capacity as set out by the Tripling Scenario. To measure the impacts of flexibility options, a baseline is defined where no flexibility option is introduced in the Tripling Scenario, but capacity of wind and solar energy is distributed in a system friendly way. Individual flexibility options and their application alternatives (where applicable) are investigated as additional cases (see Table 3). In addition, a sensitivity analysis is carried out to analyse the impact of applying flexibility options on lower shares of wind and solar, and to estimate the costs and benefits using different capital cost assumptions.

Table 3: *Flexibility options considered for the Tripling Scenario*

Flexibility Options	Location Strategy	Application Alternatives	Explanation
Reference Case	System-driven	-	No flexibility option
Battery storage	System-driven	Li-Ion NMC	600 MW distributed battery storage 300 MW allocated for frequency control reserve and 300 MW for market and redispatch
		Li-Ion LFP	
		Li-Ion LTO	
		Li-Ion NCA	
		ZBFB	
		VRFB	
		VRLA	
		Lead Acid Flooded	
		High Temp NaNiCl	
		High Temp NaS	
		Mechanical CAES	
Pumped-hydro storage	System-driven	-	Gökçekaya plant, 1.4 GW. 400 MW allocated for frequency control reserve
Flexible thermal generators	System-driven	-	Fast responding thermal units with frequency control reserve capability
Demand response	System-driven	-	Ability to reduce demand at any given hour by up to 5%. In this study only demand reduction is modelled. This choice was made because increasing the load requires ready and waiting load for this particular order which is more difficult to implement on the customer side. Accordingly, reduced demand is not recovered in a later hour.

Note: Gökçekaya plant is in the centre of the Anatolian peninsula, close to load centres at northwest and on the main transmission corridors from southeast Turkey. The location of the plant allows it to play an important role regarding the constraints on the main transmission corridors that feed the highly industrialised and populated Istanbul-Adapazarı region.

2.2 Input datasets and cost assumptions

Three main datasets are utilised in the analysis as shown in Figure 2. The main data backbone is the existing and planned transmission grid as well as power plant fleet expected to be in place between 2016 and 2026. For the analysis, certain variables and approaches were kept unchanged across different scenarios, whereas other parameters have been defined based on the particular characteristics of the investigated flexibility option.

2.2.1 Existing and planned generation/transmission components

The analysis is carried out for the Tripling Scenario of SHURA's grid integration study that assesses the integration of 30 GW onshore wind and 30 GW solar photovoltaic (PV) capacity by 2026. The capacity mix and total electricity demand of the Tripling Scenario are shown in Table 4. Turkey's total electricity demand is projected to grow on average by around 5% per year, indicating a continuation of the growth trend observed in recent years (excluding the marginal growth in 2018). Details of the analysis to arrive at this capacity mix can be found in SHURA's grid integration study (Godron et al., 2018).

Table 4: *Overview of project electricity generation capacity for the Tripling Scenario, 2016-2026 (in GW)*

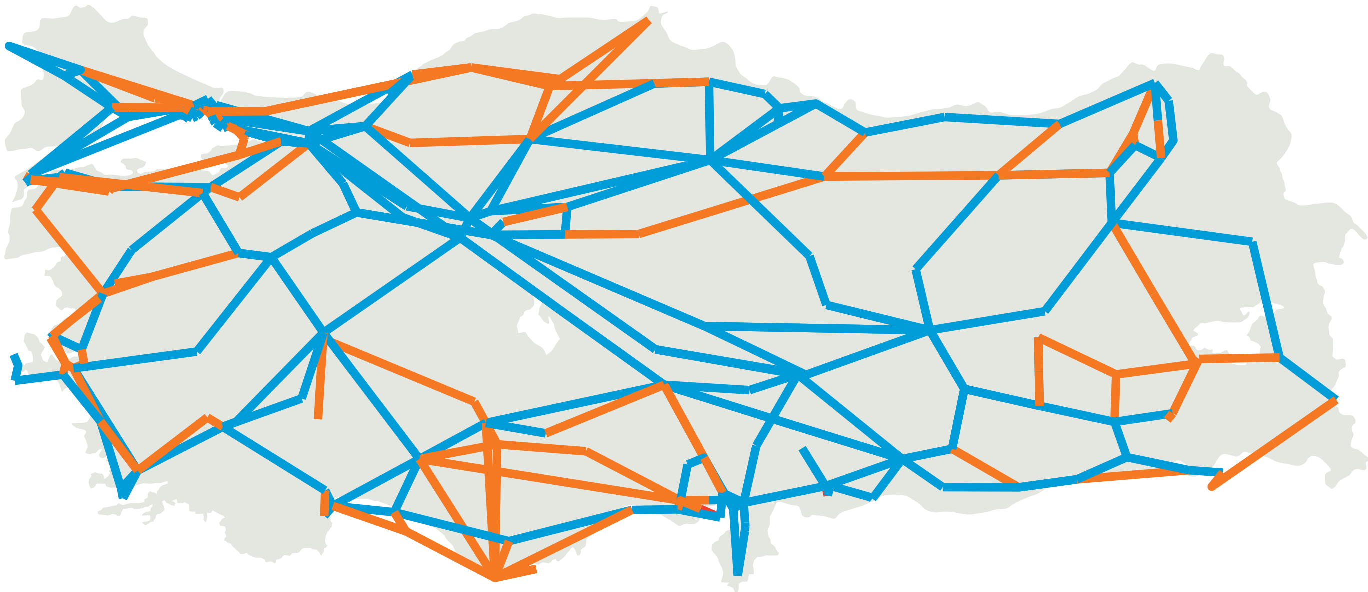
	2016	Tripling Scenario
Total electricity demand (TWh/yr)	**278**	**440**
Peak demand	44	69.2
Imported coal	7.5	10.2
Hard coal	0.6	0.6
Lignite	9.3	13.3
Natural gas	25.5	28.1
Nuclear	-	6.8
Hydropower	26.7	37.5
Onshore wind	5.8	30.0
Solar PV	0.6	30.0
Geothermal	0.8	1.45
Others	1.7	1.7
Total	**78.4**	**159.6**

Note: "Others" include dispatchable generation capacity from renewable waste, biogas and oil products.

All scenarios investigated in SHURA's grid integration study contain the key parameters and assumptions on planning according to TEİAŞ's TYNDP to 2026. In its plan, which was released in 2016, TEİAŞ used different approaches for 400 kV and 154 kV transmission grids (see Figure 5 and Figure 6):

- Ten-year investment plan (2016–2026) for the 400 kV system
- Five-year investment plan (2016–2021) for the 154 kV system (extrapolated in this analysis to 2026 based on demand growth)

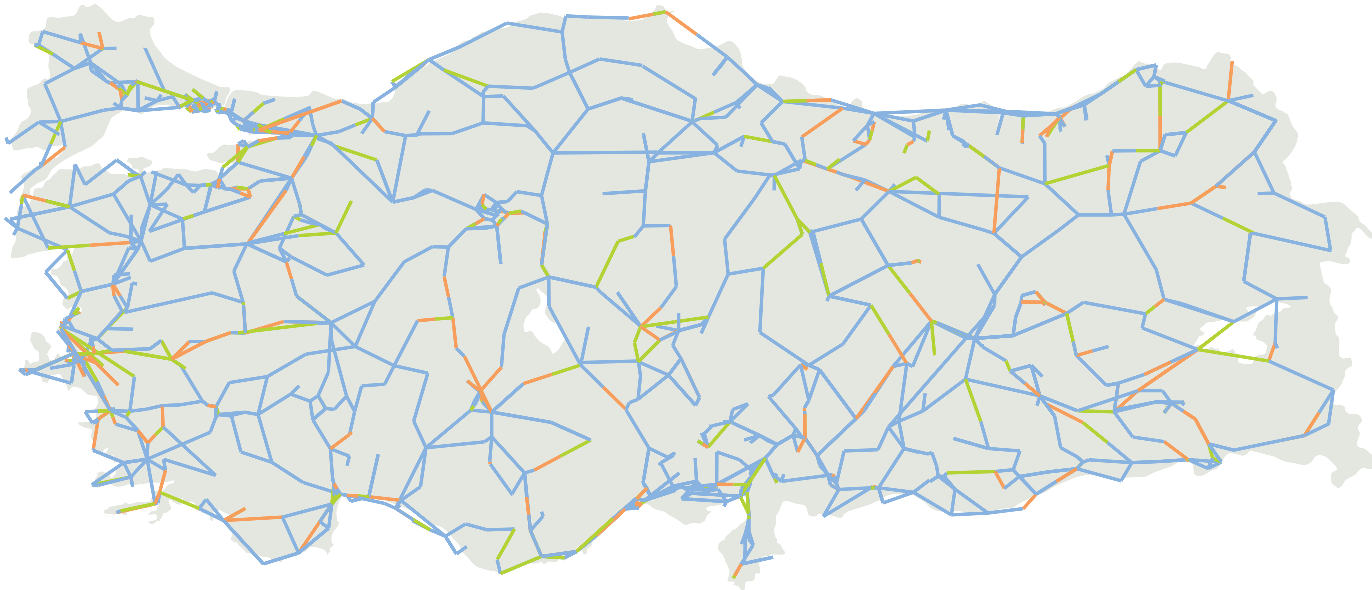
Figure 5: *400 kV network model for 2026*



Existing network elements in 2016 Planned TEİAŞ investments until 2026

Note: TEİAŞ model, limited investments at the 400 kV level

Figure 6: *154 kV network model for 2026*

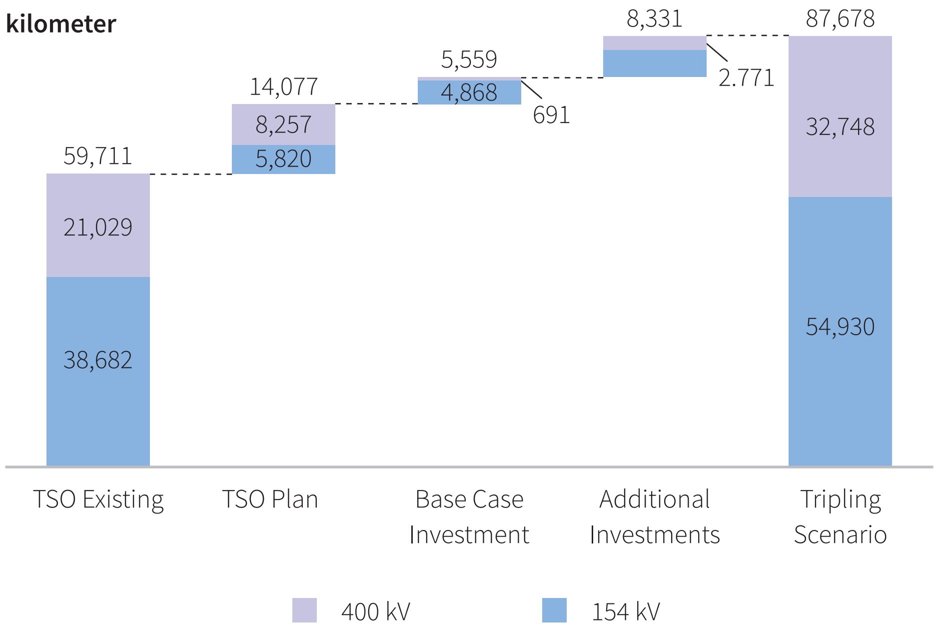


Existing network elements in 2016
Planned TEİAŞ investments until 2026
Additional investments for Base Case Scenario (economically driven or security/reliability driven)

In addition to these investments, in the Tripling Scenario, additional transmission grid investment needs to integrate 60 GW of wind and solar capacity were estimated (see Figure 7 and Figure 8) (Godron et al., 2018). The calculation of costs concerning these planned, additional and further investments are defined in section 2.2.2.3. Finally, generation profiles of individual renewable energy power plants in hourly resolution are determined based on the methodology employed in the SHURA grid integration study (Godron et al., 2018).

Figure 7: Additional investment needs according to the system-driven strategy of the Tripling Scenario, 2026

Figure 8: Total transmission system investment needs in the Tripling Scenario, 2026



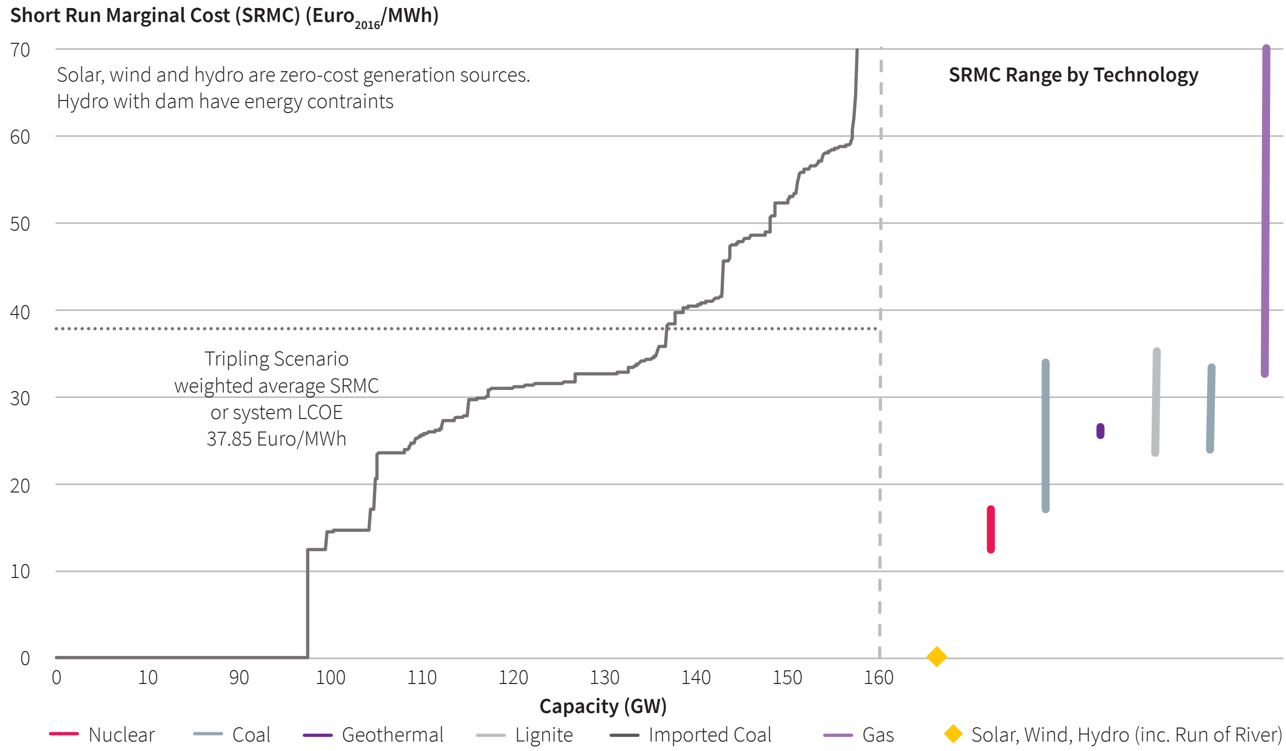
2.2.2 Cost parameters independent of scenarios

The cost parameters that are kept constant for all simulation cases are: the generation cost curves of conventional units (excluding hydropower plants), the approach to calculate the cost of renewable curtailment and the investment cost of transmission grids per kilometre (km).

2.2.2.1 Generation cost curves

The cost of electricity generation is defined separately for each conventional unit as the relation between the generation in MW versus the short-run marginal cost (SRMC) of generating one megawatt-hour (MWh) of electricity. There is a SRMC range for each technology. These ranges are determined based on the day-ahead market clearing price and total generation for each technology in 2016 (the complete yearly dataset with hourly resolution is utilised) (EPİAŞ, 2019). For each technology, separate cost curves that take the ranking of individual units into consideration are plotted. These curves consider economies of scale (the size of the unit and plant) and the efficiency of individual units (assumed based on the year of installation and the respective heat rate) (NREL, 2017). The rationale behind this approach is that the SRMC of larger and newer plants is lower than that of older and smaller ones. The SRMC range for conventional technologies as well as the combined cost curve for the entire power plant fleet in the Tripling Scenario for the year 2026 are shown in Figure 9.

Figure 9: *Short-run marginal costs of the Tripling Scenario, 2026*



2.2.2.2 Renewable curtailment

Although there is currently a feed-in tariff scheme that provides a purchase guarantee at a predetermined price for renewable energy-based electricity generation, it is considered that these power plants will also become market players either on their own or by positioning themselves in a portfolio.[4] Hence, after the clearing of the day-ahead market, these plants will have a generation schedule. In this analysis, these plants are considered as zero-cost generation sources and they are assumed to bid their generation capacity[5] to the day-ahead market for free. Certainly, in the power-exchange market structure (each day), these plants are committed for the following 24 hours, assigned a generation schedule and considered to be paid by this schedule and corresponding market clearing prices.

[4] Based on the current market rules, multiple units can form a portfolio to bid in the market. Such portfolio may include renewable energy capacity as well.

[5] The hourly generation capacity of the renewable generation is determined by the same methodology presented in the grid integration study of SHURA (Godron et al., 2018).

However, in the operation of the intraday system, renewable generation is prone to curtailment to maintain secure and reliable operation. This is equivalent to getting a down-order from the dispatcher. In this case, there is a deviation between the day-ahead scheduled (and already paid) generation of renewable energy and actual generation.

For such deviations, the dispatcher collects redispatch (ramp up/ramp down, or increase/decrease in generation) bids from market participants. Although redispatch bids are determined in the analysis on the basis of cost curves, they are evaluated differently. For ramp up bids, increased generation is multiplied by the bid (Euro/MWh) and paid to the generator (renewable energy plants are not allowed to receive an order to increase their generation). In the case of ramp down bids, decreased generation is multiplied by its respective bid and paid back by the generator to the system (note that the generator was already paid by its day-ahead schedule and market clearing price). Market rules determine that the bid for generation decrease cannot exceed the market clearing price at any time. Thus, the generator enjoys the price difference between the bid for decreased generation and the market clearing price. For renewable energy plants, however, the bid for decreasing generation is equal to zero. Hence, renewable energy power plants pay nothing back and the curtailed energy from renewable energy plants is already paid by the market clearing price of the particular hour of curtailment. Accordingly, cost of renewable curtailment is calculated by multiplying the curtailed energy at every single hour with the market clearing price at the hour of curtailment (Jacobsen and Schröder, 2012).

2.2.2.3 Transmission grid investments

Additional investments in the transmission grid in comparison to the planned investments are specified via consecutive market and network simulations, which are explained in more detail in section 2.3. For each investment, a standard investment cost per unit length is considered by distinguishing the voltage level of the transmission grid. These values are determined with reference to the tariff calculations of TEİAŞ. The following investment costs are used (TÜBİTAK, 2011):

- 260,000 Euro/km of 400 kV line;
- 130,000 Euro/km of 154 kV line;
- 2,000,000 Euros for each transformer irrespective of the connection level across 400 kV, 154 kV or medium voltage lines (including substation costs per transformer).

The economic lifetime of transmission lines is taken as 60 years. These are considered in the cost-benefit comparisons based on the voltage level, distance (for lines) and number of new investments (for transformers).

2.2.3 Costs associated with flexibility options

Other than constant cost parameters, costs associated with each flexibility option have different characteristics. The rest of this section explains how these are estimated.

2.2.3.1 Distributed battery storage systems

Several distributed battery storage systems were taken into consideration. These systems are assumed to be distributed across the high- and medium-voltage substations throughout the grid based on the load level of the substation regardless of the availability of feasible locations for specific storage types (the regional distribution of battery storage systems is shown in Figure 10). Based on the utilisation of storage systems in simulations, 300 MW of usable capacity is assumed to be operated for frequency control reserve[6] (also referred to as secondary frequency control reserve) and another 300 MW of usable capacity is considered to be operated for energy shifting.[7] The allocation of capacity to operational schemes are assumed to be based on expected additional demand for frequency control at penetration levels of 60 GW of wind and solar capacity. Similar conclusions are also drawn by the International Renewable Energy Agency (IRENA) as half of current utilisation of battery storage is used for frequency regulation and the other half is expected to be used for energy shifting by 2030 (IRENA, 2017). Other applications like peak shaving, micro/nano grid or community storage applications are excluded from the scope of this analysis as the control of TEİAŞ in these areas will be limited and as these technologies are assumed not to be common till 2026 to create a major impact.

The energy to power ratios and other characteristics (like cycle efficiency, depth of discharge, etc.) of selected technologies are all considered based on a study by IRENA (IRENA, 2017). Bearing their application types and characteristics in mind, investment (Euro/MW) and operation (Euro/MWh) costs are determined for each battery storage technology. Although the study has multiple reference values for the years between 2016 and 2030, 2020 reference values were used as a conservative assumption (the IRENA cost-of-service tool does not explicitly provide a LCOE but calculates investment and operation costs separately). Also the calculated costs for storage systems are consistent with a recent study conducted by the European Comission and the Joint Research Centre (JRC and EC, 2018) which states that the cost for installation of stationary storage systems (Li-ion) is expected to have an average cost below 800 Euro/kWh capacity by 2020.[8]

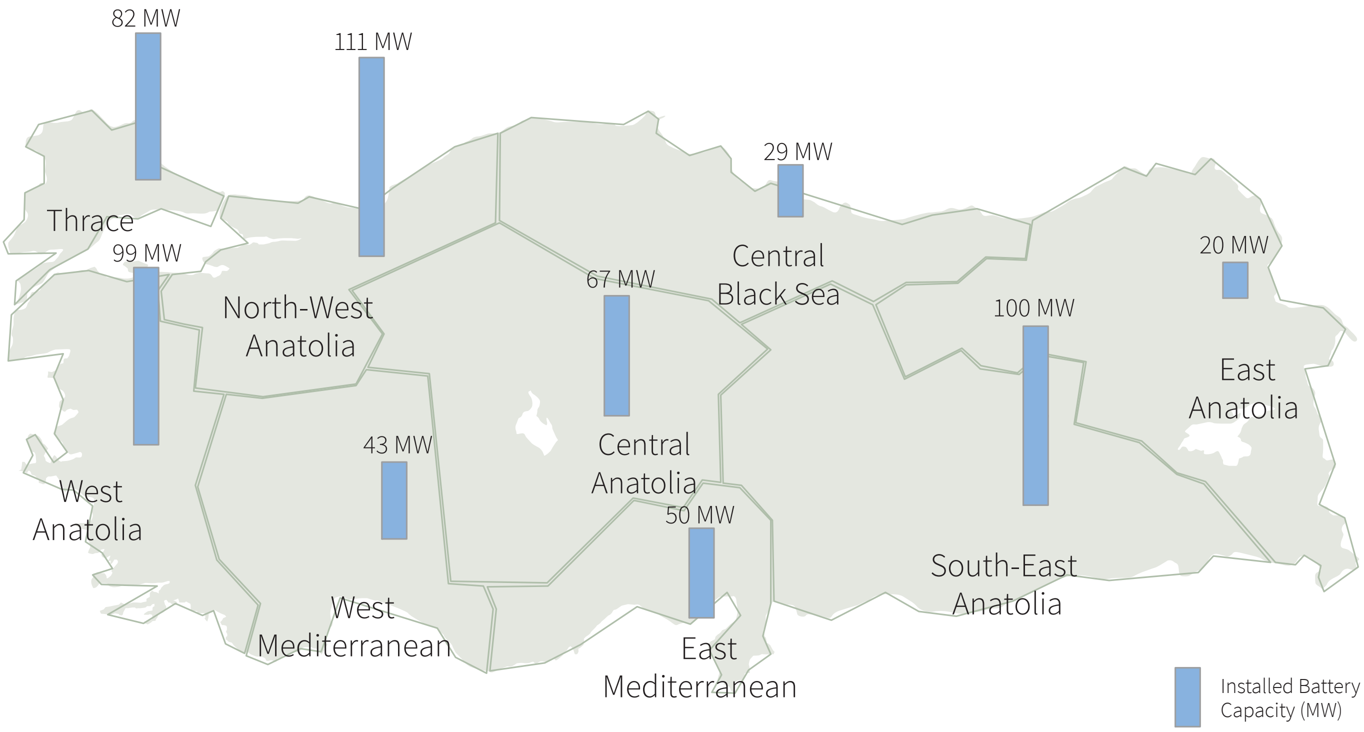
Table 5: *Investigated storage technologies and critical parameters*

Storage Technology	Calendar Life (Years)	Depth of Discharge (%)	Round-Trip Efficiency (%)	Power installation cost (USD/kW)	Energy installation cost (USD/kWh)
CAES	50.00	40%	64%	780	50
Flooded LA	9.94	50%	83%		120
VRLA	9.94	50%	81%		215
Li-Ion (LFP)	13.55	90%	92%		440
Li-Ion (NCA)	13.55	90%	95%		275
Li-Ion (NMC)	13.55	90%	95%		320
Li-Ion (Titanate)	16.94	95%	97%		840
NaNiCl	16.88	100%	85%		310
NaS	18.82	100%	81%		210
Vanadium Flow	13.72	100%	72%	1,065	255
ZnBr Flow	11.44	100%	72%		665

Source: IRENA (2017)

[6] For frequency control reserve applications, IRENA assumes energy to power ratio as 2, i.e. for an installation of 1 MW, the storage capacity is assumed as 2 MWh.
[7] For energy shifting applications, IRENA assumes energy to power ratio as 8, i.e. for an installation of 1 MW, the storage capacity is assumed as 8 MWh.
[8] Considering the values in "Li-ion batteries for mobility and stationary storage applications" study (JRC and EC, 2018) and using assumptions defined in Section 2.2.3.1, a 3,000 MWh installation is used in storage scenarios, which corresponds to an investment of 2.4 billion Euros. When this value is levelised in view of the annual demand in Turkey (440 TWh in 2026) and the lifetime of the investment, the result is in the same ballpark with the values calculated in this study.

Figure 10: *The assumed regional distribution of battery storage systems of 600 MW, 2026*



The storage system considered for investigation is Gökçekaya power plant which has a total installed capacity of 4x350 MW. 100 MW capacity of each unit is allocated for frequency control reserve and the rest of the capacity is available for other services.

2.2.3.2 Pumped-hydro storage

Similar to the distributed battery storage systems, the investment and operational costs of pumped-hydro storage are calculated by using the same IRENA study and the IRENA cost-of-service tool (IRENA, 2017) as well as other literature that provide a data reference for Turkey. The storage system considered for investigation is Gökçekaya power plant which has a total installed capacity of 4x350 MW. This assumption is based on previous studies of Elektrik Üretim A.Ş. (EÜAŞ) and it was found as a reasonable capacity assumption by Enerji ve Tabii Kaynaklar Bakanlığı (ETKB) in stakeholder consultation meetings. 100 MW capacity of each unit is allocated for frequency control reserve and the rest of the capacity is available for other services. Each unit of the plant is assumed to have a variable speed technology which allows commitment for a wide range of operations. The critical parameters for pumped-hydro storage are provided in Table 6.

Based on the IRENA study, the investment cost of a pumped-hydro storage with a capacity of 1.4 GW is estimated slightly above 1.8 billion Euros. A study conducted by Japan International Cooperation Agency (JICA) provides a lower value, in the order of 1.25 billion Euros, for the investment cost of Gökçekaya plant (JICA, 2011). These two values are considered as a range in this analysis.

Table 6: *Critical parameters for pumped-hydro storage*

Storage Technology	Calendar Life (Years)	Depth of Discharge (%)	Round-Trip Efficiency (%)	Power installation cost (USD/kW)	Energy installation cost (USD/kWh)
Pumped-hydro	60.00	90%	80%	840	21

Note: Depth of Discharge is only used for modelling purposes for pumped-hydro storage; their energy storage capacity in terms of CAES is much higher compared to battery systems.

2.2.3.3 Retrofitting old coal-fired power plants

Hard coal- and lignite-fired power plants that are in operation in Turkey have limited flexible generation capacity. In this analysis these plants are modelled with no secondary frequency control reserve, high minimum generation (P_{min} at 90% of P_{max}), slow ramp rate (maximum hourly change at 25% of maximum capacity) and long minimum up/down-times (if the unit is committed, it should remain on for at least 4 hours and if it is turned off, it should remain off for at least 4 hours), which can be considered as conservative assumptions. These assumptions are consistent with the general operational practice of thermal units in Turkey (excluding the newer technology plants). Details are provided in Figure 11.

The limited flexibility capacity creates a challenge for the transmission system operator in handling rapid changes in electricity generation from variable renewable energy sources. As a flexibility option, the existing plants are retrofitted. It is assumed that retrofitting would allow power plants to be available for frequency control reserve (5%), low P_{min} (50% of the P_{max}), fast ramp rate (100% power change within an hour) and shorter minimum up/down-times (1 hour up and 1 hour down time). Through these changes the power plant operational flexibility is increased up to a level that is practically considered as standard performance in many OECD countries. The state-of-the-art flexibility, both in terms of minimum load and ramp rates, is still considerably higher than what is modelled in this analysis (Agora Energiewende, 2017).

Figure 11: *Parameters defining the flexibility of thermal units*

Obviously, flexibility of the units is also dependent on the quality of coal or lignite used as fuel. As the calorific value of the coal decreases, it gets harder to reach these flexibility measures. The calorific value of lignite plants in general ranges between 1,500 and 2,500 kilocalories (kcal) per kilogram (kg) lignite in Turkey, with some reserves presenting even lower values (Elevli and Demirci, 2004). Although these values seem to be low, there exists examples of power plants that operate with similar coal qualities (1,900-2,150 kcal/kg) and can yet provide the defined flexibility abilities since 2012 (e.g. Boxberg Unit R in Germany) (Heimann, 2012). Assuming that similar adaptations can also be made in Turkey in the next decade, the retrofit parameters are applied to lignite-fired units as well.

There are a variety of retrofitting options to improve different operational aspects of thermal power plants. For the purposes of this analysis, a set of retrofitting options that improve ramp rates, start-up/shut-down times and P_{min} have been taken into consideration.

There are a variety of retrofitting options to improve different operational aspects of thermal power plants. For the purposes of this analysis, a set of retrofitting options that improve ramp rates, start-up/shut-down times and P_{min} have been taken into consideration (Venkataraman et al., 2013). Specifically for P_{min}, an additional evaluation has been carried out based on the study prepared by the Agora Energiewende (Agora Energiewende, 2017). Based on these evaluations and expectations about the costs of retrofitting, a range of costs for three different sizes of power plants, namely for small (<250 MW), medium (250 MW-600 MW) and large (>600 MW) scale units, have been estimated (see Table 7). Given that various suites of retrofitting options can be introduced, minimum and maximum values have been defined. Considering retrofitting as a major maintenance operation, two main maintenance points in time are taken into consideration in the calculations: at 10 and 20 years old plants, this corresponds to the PJM (PJM, 2019) approach of evaluating the unit cost in their market. These two values are used to define a range of costs for retrofitting. In other words, retrofitting costs were levelised in consideration of these two points in time.

Table 7: *Utilised retrofit costs per installed capacity based on unit size*

	Cost (Euro/kW)		
Considered Retrofits	Small <250 MW	Medium 250-600 MW	Large >600 MW
Minimum	191.32	120.55	110.54
Maximum	255.09	160.74	147.38

Note: The data from the study by Venkataraman et al. (2013) in USD are converted to 2016 USD by inflation rates (US Bureau of Labor Statistics, 2019) and then to Euro by using average exchange rates.

Unlike other flexibility options, demand response is assumed to have no installation and operation cost.

2.2.3.4 Demand response

Based on the developments in technology and regulation, end users are increasingly assumed to be more sensitive to electricity prices either directly or by participation in aggregators. Demand response in Turkey is assumed to be comparable with current examples in Belgium, France and the Republic of Korea (as the data related to these countries are available). From the cost perspective, there are two main factors to be considered: the cost of infrastructure to realise demand response (communication, adaptation of appliances/systems, etc.) together with its continuous operation to maintain availability and activation of the demand response by the dispatcher order and/or signal in case of a necessity.

Unlike other flexibility options, demand response is assumed to have no installation and operation cost. The rationale behind this assumption is that demand response is assumed to be performed following a signal from the transmission system operator, which can be communicated online (or as an internet of things application). The costs associated with the development of these technologies are assumed to be undertaken by appliance producers or vendors of large system providers. The main idea is that the increase in renewable energy will also trigger fast digitalisation in all sectors. As a result, appliance or system developers will be forced to incorporate such technologies in their products for the sake of competition.

Although demand response is assumed not to have an installation and operation cost, its activation requires end-user motivation, which is usually more expensive than the activation of redispatch from conventional units. The activation cost of demand response is a part of the market and network simulation, and the algorithm chooses the activation of demand response when all other alternatives are ineffective or more expensive. Hence, although the activation cost is high, it is used when it is beneficial. Therefore, whenever demand response is activated (even with a very high activation cost), it reduces the system LCOE. Accordingly, demand response creates benefits in the system LCOE and does not incur any installation and operation cost.

To estimate the activation cost of demand response, current applications in three countries have been considered. For the sake of competitiveness, the costs of different markets were normalised by the average of the highest priced 100 hours of the year (approximately 1% of total time). Furthermore, the normalisation procedure was performed by both day-ahead market (DAM) and balancing market (BM) prices (Energy Pool, 2016). Based on these reference prices, the cost of demand response for 1 MWh was assumed as 800 Euros, which can be considered as the bid of demand responding parties to the market.

From the modelling perspective, demand response was considered as generators at each load location with very high generation (or activation of demand response) costs (800 Euro/MWh). On the other hand, demand respond stands in contrast to battery storage, since no installation and operation costs were assigned to the former. Certainly, demand response is also limited with the available load and its responsiveness to the price. A limit that represents demand response as 5% of the load at location and the time in one year (in power at each hour) was defined for generators. This practically means that demand response is limited to 5% of the load in all substations in the network.

Table 8: *Calculation of the cost of demand response*

	France AOE	Korea Rel.DR	Belgium R3DP	Belgium SDR	Average	Turkey
Realised Unit Cost (Euro/MWh)	1,200.00	1,253.33	1,000.00	687.50	1,035.21	
Avr. DAM Price (Highest 100 Hours) (Euro/MWh)	113.89	141.11	99.72	99.72	113.61	102.35
Per Unit Value (Based on DAM Price)	10.54	8.88	10.03	6.89	9.09	
Avr. BM Price (Highest 100 Hours) (Euro/MWh)	151.11		206.11	206.11	187.78	131.18
Per Unit Value (Based on BM Price)	7.94		4.85	3.34	5.38	
Cost (Based on DAM Price) (Euro/MWh)					102.35 x 9.09 =	929.89
Cost (Based on BM Price) (Euro/MWh)					131.18 x 5.38 =	705. 23

2.3 Consecutive market and network simulation

In this section, the methodology employed in the consecutive market and network simulation approach is explained. Market and network simulations are the core of the methodology. In the market simulation, supply and demand balance of the power system is satisfied hourly for the entire year at minimum total cost of generation and minimum curtailment of renewable electricity generated from wind and solar PV for the Tripling Scenario in the year 2026.

Market simulation optimises the day-ahead power-exchange market clearing process in Turkey's electricity market. Network simulation represents the role of transmission system operator in determining the secure and reliable operation of the grid.

Market simulation optimises the day-ahead power-exchange market clearing process in Turkey's electricity market. Network security and reliability constraints as well as spinning reserve requirements were ignored in the market simulation, in contrast to the power exchange market.[9] Indeed, market simulation represents the role of the market operator in determining the market clearing price (MCP)[10] in the day-ahead power exchange market, not only for a single day but for an entire year. Main inputs of the market simulation are as follows (Godron et al., 2018):

- A reference transmission grid model for 2026,
- Generation capacity scenario including wind and solar for 2026,
- Merit order which includes the SRMC of power plants and curtailment costs of renewables,
- Operational constraints of conventional power plants,
- Energy constraints of dam-type hydropower plants in weekly resolution,
- Time series of total demand in hourly resolution,
- Time series of wind and solar generation in hourly resolution.

Main outputs of the market simulations include:

- Market clearing for the target year in hourly resolution,
- Unit commitment of conventional generators in hourly resolution,
- Cost of generation in hourly resolution,
- Amount of wind and solar generation curtailment, if any,
- LCOE and impact of portfolio cost (as presented in Figure 3).

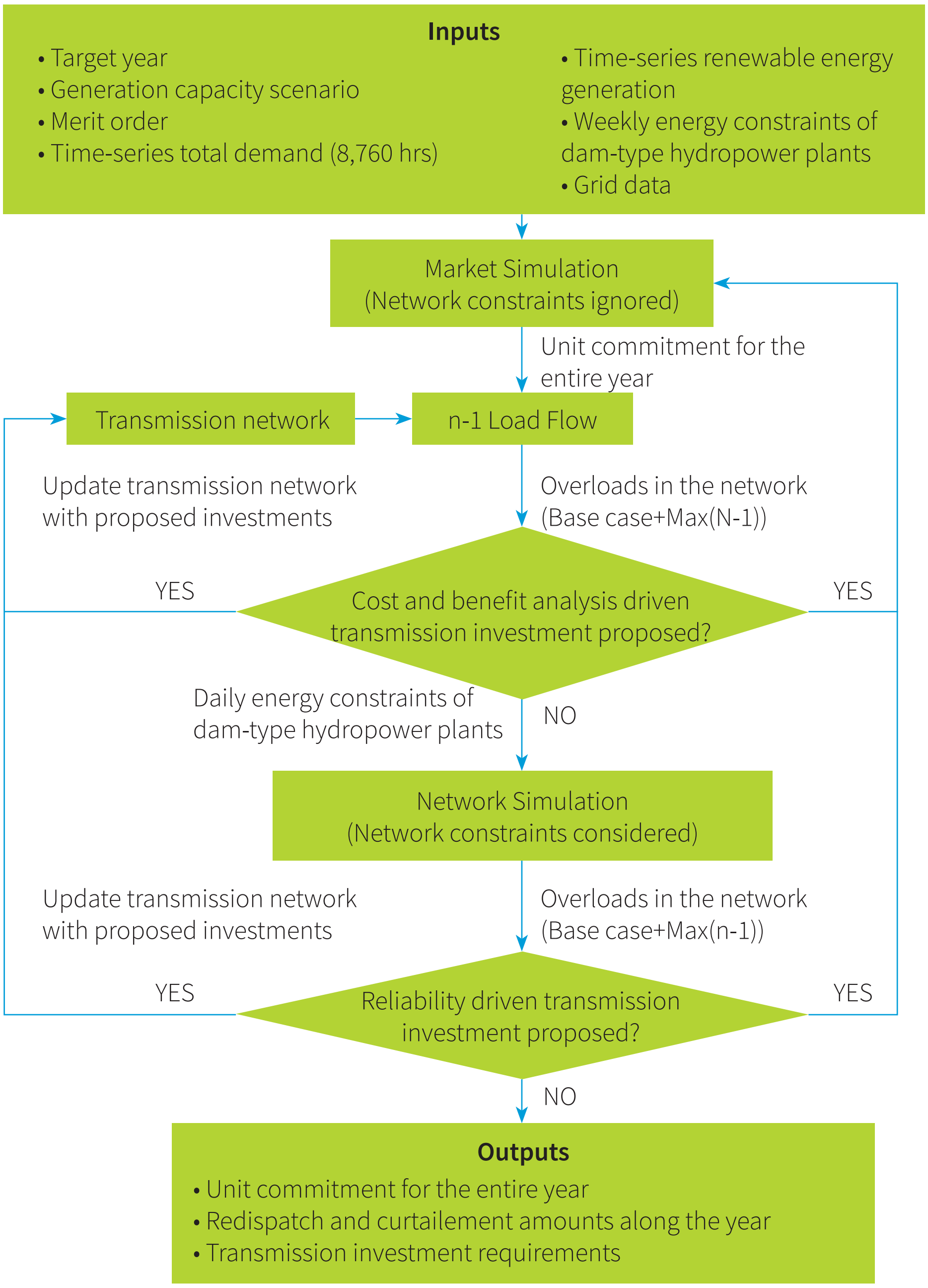
Outputs of the market simulation are given to the network simulation as input. Network simulation represents the role of transmission system operator in determining the secure and reliable operation of the grid. While in the market simulation, there is a detailed resolution regarding time only (8,760 hours), complexity is much higher in the network simulation as there is also a high resolution in space.

The flow chart of the consecutive market and network simulation approach is presented in Figure 12. The first step is the market simulation, which clears the power exchange market along the year based on a merit order. It is a mixed-integer-programming problem including dynamic unit commitment of power plants under short- and long-term operational constraints. The mixed-integer-programming problem was decomposed into a master problem and sub-problems based on Benders decomposition technique (Bahiense et al., 2011). Master problems involve calculating unit commitment by augmented Lagrangian relaxation for the constraints (Latfjou et al., 2010).

[9] Price-Based Unit Commitment algorithm was used to represent the power exchange market structure.
[10] Market clearing price (hourly resolution) in the day-ahead market. Market clearing price is defined by the last committed generator in the day-ahead market at each hour.

Unit commitment in the market simulation provides market tendency in a power exchange market. Although in a day-ahead market commitment of the power plants are defined based on bids and offers of market players, in a long-term planning problem, unit commitment based on SRMC of power plants is the widely accepted approach in the literature. Since the market clearing price is defined by the marginal plant in a marginal based power exchange market, the main assumption in the study is that all market players make their bids based on their SRMCs (Dui and Zhu, 2018). Following the market simulation, iterative network simulations were carried out in order to estimate the necessary transmission investments based on n-1 criteria, congested energy and cost-benefit analysis. After finalisation of transmission network investments, final market and network simulations, which are designed to minimise the total cost of generation by selecting the most efficient redispatch and curtailment options, were carried out according to n-1 criteria and reserve requirements. A detailed flow chart of the process is given in Figure 12.

Figure 12: *The flow chart of the consecutive market and network simulation approach*



2.4 Levelisation of costs and benefits

The comparison of the cost and benefit impact of each option was made on the basis of the weighted average short-run marginal cost in Euro per MWh, which is referred to as the system LCOE. The short-term system LCOE is the annual average cost of energy for the Tripling Scenario without any flexibility option. This parameter was calculated via market and network simulations as described in section 2.3.

For the purposes of the analysis, short-term system LCOE and system LCOE were calculated initially. Then, cost items related to a flexibility option were calculated as an annual total and, finally, based on these figures, costs and benefits of each flexibility option were calculated separately. Subsequently, the flexibility option was added into the model and simulations were repeated to arrive at the system LCOE.

Secondly, the cost of flexibility option was calculated considering investment costs (Inv. Cost) and annual operation costs (Op. Cost). In annualising the investment costs, a standard discount rate and the economic lifetime of the flexibility option were used to determine an annuity factor. The annual discount rate (ADR) was assumed as 10%. In addition to this cost, an operation cost was also calculated based on the utilisation of the flexibility option as computed by the network simulation. As a final step, the annual cost was divided by the total electricity demand in the system to estimate the impact on the system LCOE as given in the formula below.

$$Flexibility\ Cost\ \left(^{EUR}/_{MWh}\right) = \left[Inv.Cost\ x\ \frac{ADR\ x\ (1+ADR)^{Lifetime})}{(1+ADR)^{Lifetime}-1)} + Op.Cost \right] \Big/ (Total\ Demand)$$

The minimum cost operating point of a power system is the result of the day-ahead market. However, due to operational requirements and to ensure the security and reliability of the power system, the system operator performs redispatch and/or curtailment procedures. These procedures shift the operating point of the system to a more costly level. In principle, flexibility options have the ability to reduce these changes by allowing the system operator to solve the problems without resorting to redispatch and curtailment. Hence, the operating point of the system is closer to the market solution, which implies a smaller difference between LCOE and the system LCOE. The difference between the short-term system LCOE (without flexibility option) and the system LCOE (with flexibility option) was used as a proxy of the benefits of the flexibility options.

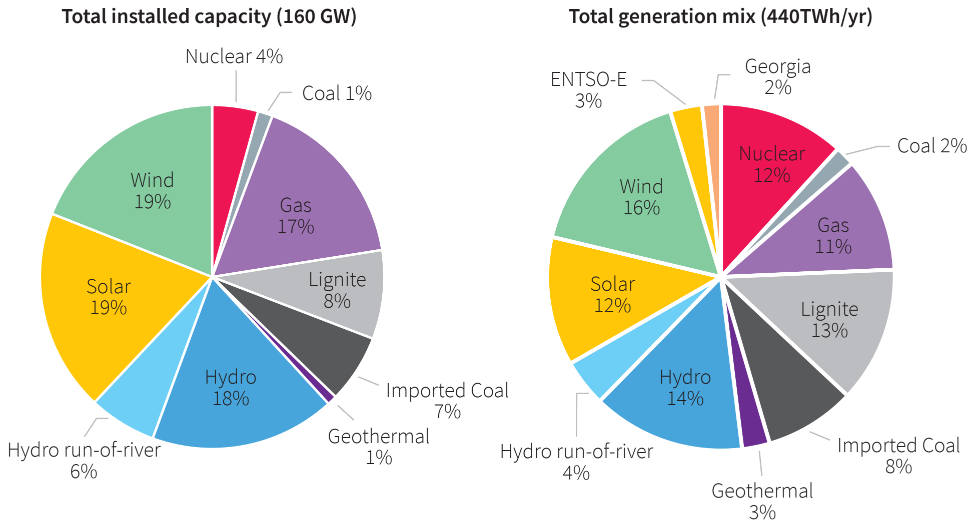
3. Estimation of the Costs and Benefits of Flexibility Options

3.1 Defining the baseline: Tripling scenario with system-driven approach and without flexibility options

The electricity generation from wind and solar PV represents around 30% of the total electricity demand in 2026. Another 20% of the total electricity demand is supplied by other renewable energy sources.

Installation of 30 GW of wind and 30 GW of solar PV capacity by 2026 in the Tripling Scenario is taken as a baseline in this analysis. Here, it is assumed that wind and solar PV plants are distributed based on a system-driven approach, i.e. the capacity is distributed in areas with large demand and stronger grids. While this may not be the most economically efficient approach, it is used as a starting point of this analysis given that it provides significant benefits to reduce curtailment, redispatch and additional investments in transition grids. Even though the analysis could be refined by economic optimisation and spatial diversity, this was left outside of the scope of this analysis. The electricity generation from wind and solar PV represents around 30% of the total electricity demand in 2026. Another 20% of the total electricity demand is supplied by other renewable energy sources (see Figure 13). However, no option is introduced to increase system flexibility.

Figure 13: *Total installed electricity generation capacity and the generation mix in the Tripling Scenario without any flexibility option*



The system-driven approach to locate wind and solar energy was introduced as part of the baseline defined in this study since this approach has already provided substantial system benefits. Accounting for this reduces the contribution required by other flexibility options to ensure a secure and reliable operation of the transmission grid. Therefore, in this section the costs and benefits of switching from a resource-driven to a system-driven approach are explained. More detailed findings are available in a recent study prepared by SHURA (Saygin et al., 2018).

Tripling the installed capacity to 60 GW by 2026 in comparison with TEİAŞ's plan would render solar and wind the largest source of electricity generation in Turkey with a total share of 31%. A higher share of renewables would reduce the electricity provided by fossil fuel-fired power plants.

Assuming that a resource-driven approach of wind and solar allocation is adopted and additional flexibility in the system does not exist, 30% of additional investments in transmission line capacity and 20% in transformer substation capacity would be required by 2026, compared to TEİAŞ's TYNDP. The annual required investment would thereby increase from 385 million to 530 million Euros.[11]

A more balanced distribution of wind and solar PV capacity would facilitate integration. In such a system-driven approach, wind and solar PV capacity is distributed across the country based not only on resource quality, but also on the basis of local electricity demand and grid strength.

A more balanced distribution of wind and solar PV capacity would facilitate integration. In such a system-driven approach, wind and solar PV capacity is distributed across the country based not only on resource quality, but also on the basis of local electricity demand and grid strength. When the system-driven approach is applied, approximately 15 GW, i.e. one quarter of overall wind and solar PV capacity in 2026, is relocated. This approach yields the following benefits:

- Additional investment needs in transmission capacity would be cut by two-thirds (2,750 km of additional lines as opposed to 8,300 km, see Figure 14). This would reduce additional annual investment needs by 100 million Euros, from 530 million to 430 million Euros (Figure 15).
- Redispatch levels would be lower as well. In 2026, the total redispatch volume required would represent 6.6% of the total electricity demand instead of 7.8% when a resource-driven approach is pursued.
- Curtailment of wind and solar electricity would fall from 2.8% to 0.8% of total generation (Figure 16).

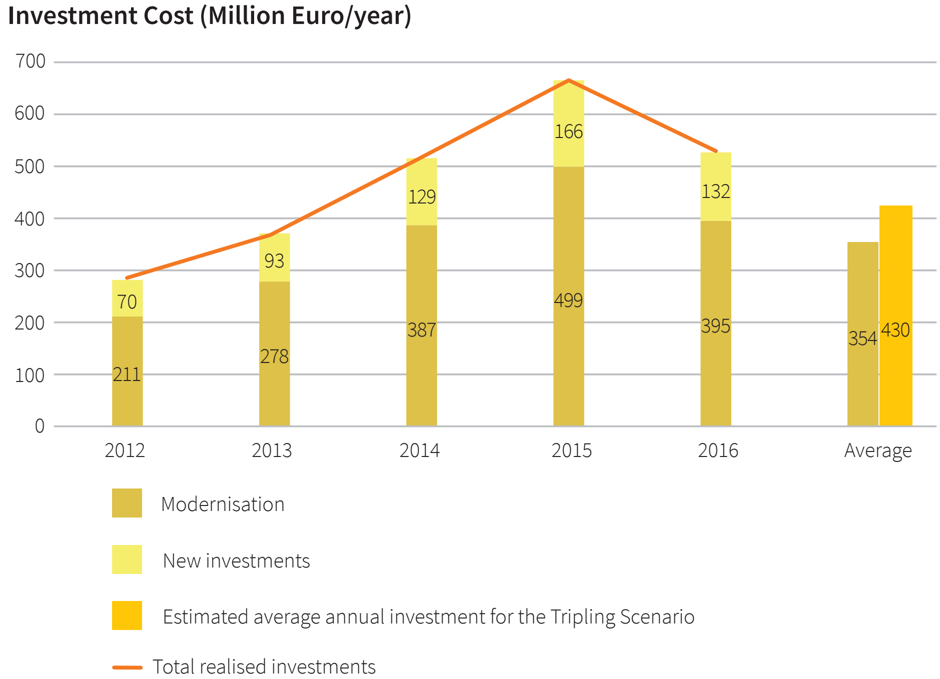
A system-driven approach would, however, result in additional costs, since capacity factors of relocated wind and solar PV plants are 4% and 10% lower, respectively, as compared to those at best sites. This results in an increase of the LCOE of the relocated plants by a maximum of 12% for the case of solar PV.

Provided that a portfolio of flexibility options is introduced to the electricity mix from 600 MW distributed battery storage, 1.4 GW pumped-hydro storage, demand response and more flexible thermal generators, curtailment would be reduced further down to 0.6% from 0.8% and redispatch to 3.1% from 6.6% (see Figure 16). In the rest of this study, we investigate the costs and benefits of flexibility options to achieve these system operation benefits.

Figure 14: *Transmission investment needs in the Tripling Scenario with the system-driven approach, 2026*

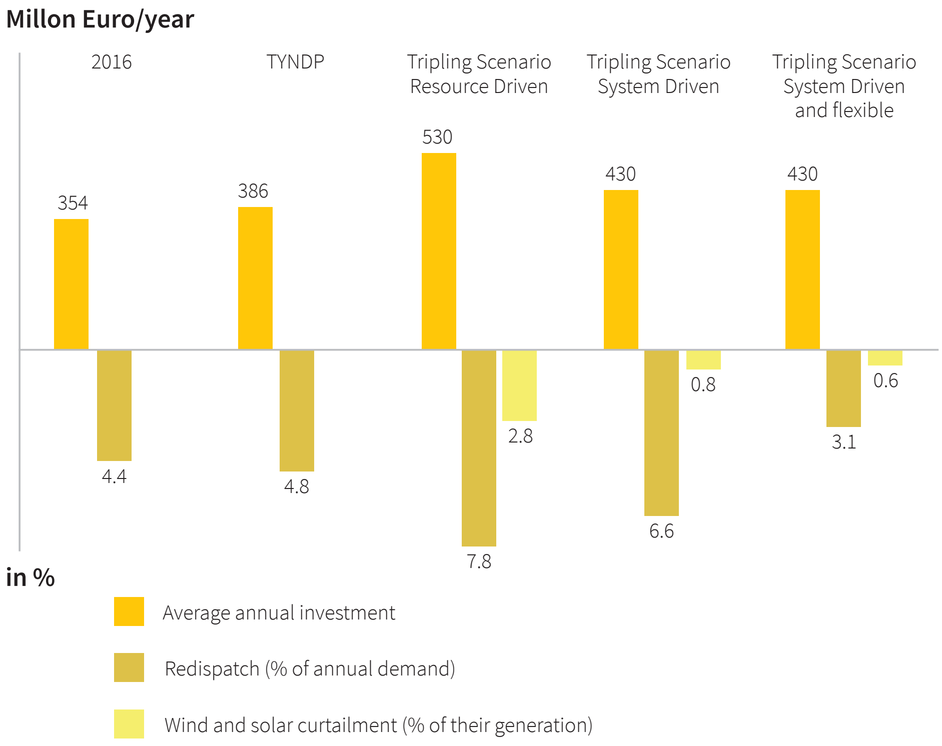
[11] This does not include grid connection costs, as these occur at different voltage levels and can be analysed properly only with a more detailed assessment of location and connection points at the distribution level. When comparing our scenarios, therefore, the grid connections in large solar PV plants were ignored.

Figure 15: *Comparison of the realised investments between 2012 and 2016 with the investments needed for the Tripling Scenario with a system-driven approach*



Note: Total realised investment figures are taken from TEİAŞ statistical information system (TEİAŞ, 2017), though no public information was available about the ratio of new and renovation investments. Given the high increase in demand and the major network investments in the last decade, renovation investment is assumed not to be larger than 25% of annual investments.

Figure 16: *Investment, redispatch and curtailment in the Tripling Scenario in 2026, compared with 2016 figures and the Ten-Year Network Development Plan of TEİAŞ*



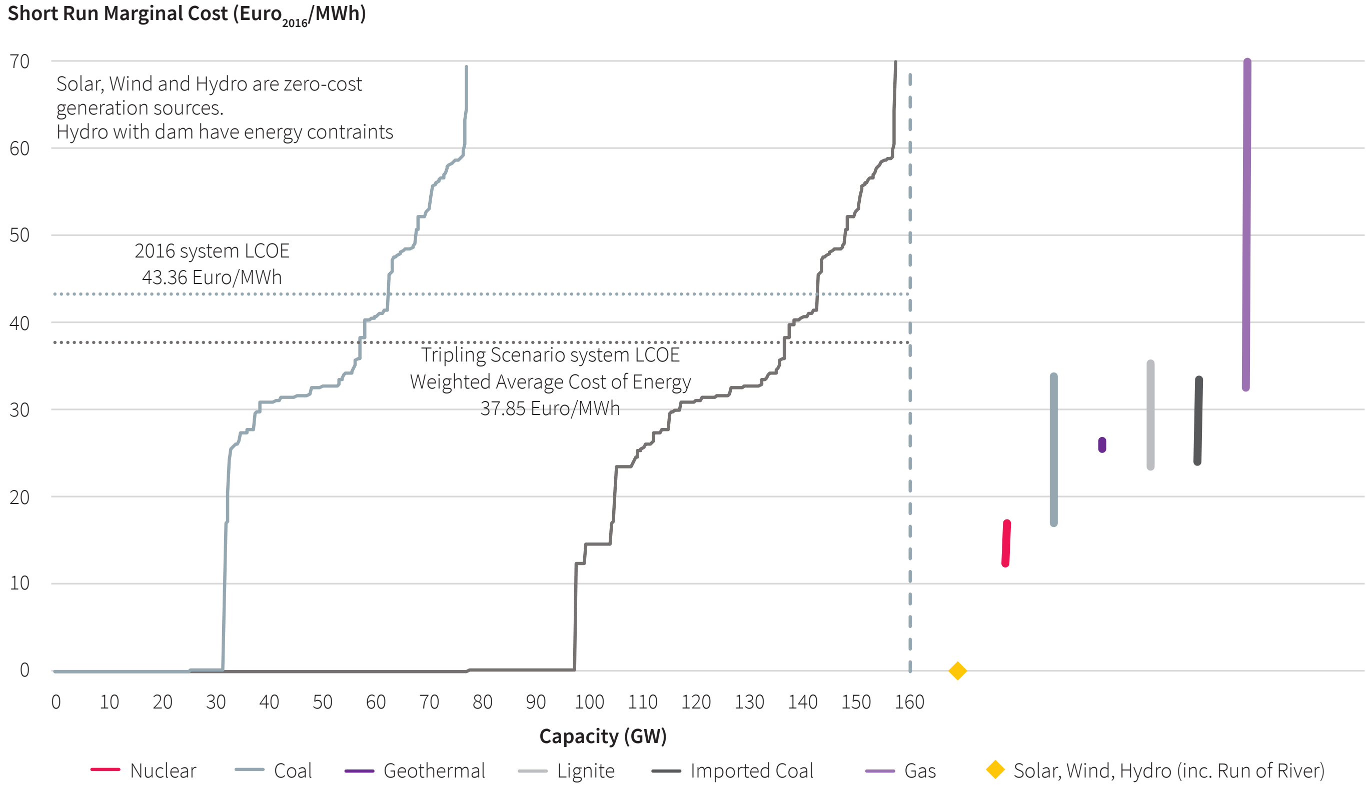
3.2 Estimating the short-run marginal costs of the baseline

The annual average cost of energy (SRMC or the system LCOE) would notably decline from 43.36 Euro/MWh in 2016 to 37.85 Euro/MWh in 2026 as the share of renewables increase.

Based on the cost curves defined in section 2.2.2.1, market and network simulations were carried out and cost of total generation (after redispatch) in each hour was calculated. According to Figure 17, additional wind and solar PV capacity added to the generation park shifts the cost curve to the right. This means that additional renewable generation (wind, solar and hydro) is prioritised by the market and thermal generation is utilised in higher load conditions. The weighted average of SRMC (or the system LCOE) would notably decline from 43.36 Euro/MWh in 2016 to 37.85 Euro/MWh in 2026 as the share of renewables increase. These estimates are comparable to others available in literature. For instance, a study carried out by Bloomberg New Energy Finance for Germany's power system with high renewable energy share in 2030 provides an estimate of 40.8 Euro/MWh (BNEF, 2018). Certainly, there are differences between the plant portfolios of two countries; yet, the calculated values are considered to be in the same ballpark.

It should be noted that the SRMC curve is based on the installed capacity which represents the theoretical maximum generation level. The demand changes hour by hour. This moves the intersection point of demand and supply curves, changing the cost at each hour. The impact of redispatch was also taken into consideration in the calculations. The cost of each hour was aggregated and the sum was subsequently averaged in order to estimate the annual average cost of energy. It should also be noted that the SRMC values shown in Figure 17 exclude the impact of costs associated with flexibility options.

Figure 17: *Short-run marginal costs in 2016 and in 2026 according to the Tripling Scenario*



3.3 Energy storage: Battery storage and pumped-hydro storage

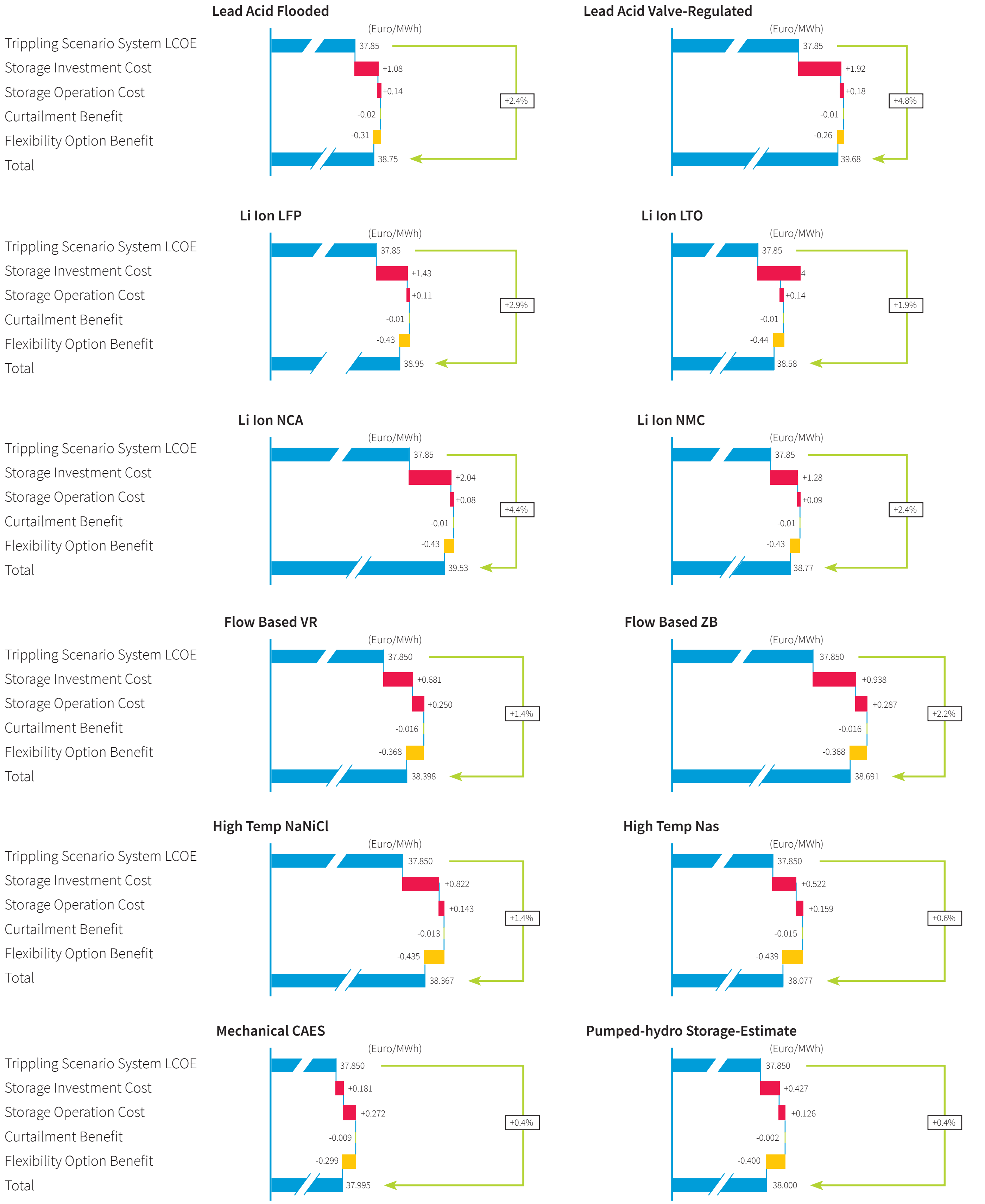
Energy storage has become one of the key areas of research as interest in battery storage technologies with electrochemical characteristics has grown. This has become particularly important as battery storage provides an important service to integrate higher shares of wind and solar energy, and becaue of the vital role it plays in electric mobility. Different technologies for battery storage exists at various levels of commercialisation. Most applications of battery storage can be found in small-scale home systems, whereas their use at medium- and high-voltage grids is scarce due to high costs. 12 types of energy storage systems were investigated under four categories for the case of Turkey.

Different technologies for battery storage exists at various levels of commercialisation. Most applications of battery storage can be found in small-scale home systems, whereas their use at medium- and high-voltage grids is scarce due to high costs. Battery storage systems increase the system LCOE at a rate between 0.7 Euro and 2.1 Euro per MWh estimated benefits range between 0.27 Euro and 0.45 Euro per MWh. The net impact of battery storage systems on the system LCOE lies between as low as 0.23 Euro to as high as 1.83 Euro per MWh.

The storage systems were investigated first by estimating their costs related to investments and operation, then by estimating their benefits due to reduction in curtailment of renewable electricity, redispatch and reserve requirements.
As shown in Figure 18, battery storage systems increase the system LCOE at a rate between 0.7 Euro and 2.1 Euro per MWh. The highest increase in costs is related to VRLA and Li-Ion technologies due to short lifetime of VRLA and higher costs of Li-Ion. By comparison, estimated benefits range between 0.27 Euro and 0.45 Euro per MWh. These benefits are due to reduced capacity requirements from conventional units (because a share of the energy storage is allocated to frequency control), reduced redispatch (because storage units can be used in charging and discharging to relax contingency overloadings) and reduced curtailment of renewable electricity (instead of curtailing generation, storage systems consume this energy by running in the charging mode). When these benefits are taken into account, the net impact of battery storage systems on the system LCOE lies between as low as 0.23 Euro to as high as 1.83 Euro per MWh.

The overall net increase in the system LCOE for featured storage technologies, pump-hydro storage and high-temperature batteries (NaS) ranges between 0.55 Euro and 0.68 Euros per MWh, where the benefits are in a relatively close range, i.e. 0.4-0.45 Euro/MWh. Among storage options, pumped-hydro storage and high-temperature batteries (NaS) were found to have the most attractive cost-benefit ratios. These findings are comparable with the range of 0%-8% estimated in an analysis by the BNEF (BNEF, 2018).

Figure 18: *Costs and benefits of energy storage on the system LCOE in 2026*

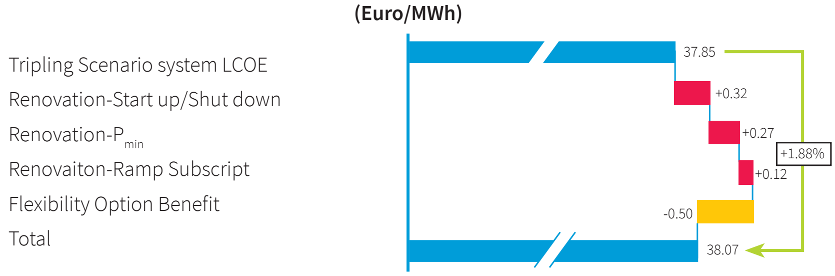


3.4 Retrofitting old coal-fired power plants

Against the total cost of retrofitting of 0.71 Euro/MWh, the benefit created by retrofitting old coal-fired power plants is equivalent to 0.50 Euro/MWh.

It is possible to balance supply and demand in a power system with high share of renewables by equipping coal-fired power plants with the ability to increase the speed of change and range of operational settings. Thus, these power plants would fulfil flexibility requirements that otherwise other sources would provide. The associated flexibility costs shown in Figure 19 are split into three main categories that can be improved: start-up/shut-down times, minimum stable generation level (P_{min}) and ramp rates. These categories comprise the main improvements targeted by the retrofit of thermal power plants (Venkataraman et al., 2013) as described in section 2.2.3.3. The majority of costs are associated with start-up/shut-down improvements. The cost of reducing the minimum stable operation point is comparable. Against the total cost of retrofitting of 0.71 Euro/MWh, the benefit created by these improvements are equivalent to 0.50 Euro/MWh. If minimum costs assumption was used (see Table 7), the total benefits of 0.50 Euro/MWh would offset the average cost of energy related to retrofits estimated at 0.53 Euro/MWh.

Figure 19: *Costs and benefits of retrofitting old coal-fired power plants on the system LCOE in 2026*



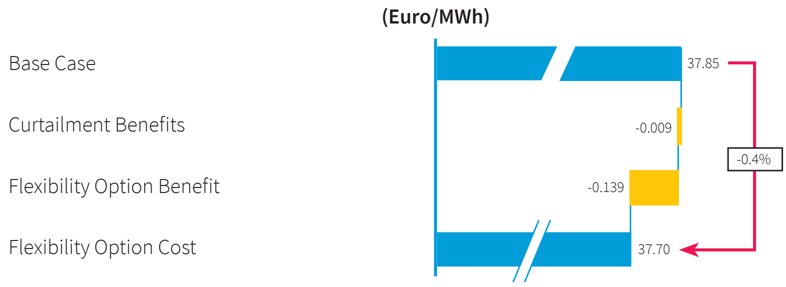
Note: The figure shows the results of the analysis performed for the maximum cost assumptions

3.5 Demand response

Although the cost of activation of demand response is high (800 Euro/MWh), its overall impact reduces the system LCOE. The demand response reduces the system LCOE by almost 0.4% with an estimated absolute benefit of 0.15 Euro/MWh, as given.

As described in section 2.2.3.4, it is assumed that there is no investment or operation cost associated with the demand response and activation of demand response is only realised in the simulation whenever it is more beneficial than the regular redispatch. Based on this approach, no cost was identified for demand response except for the cost of activation. Although the cost of activation of demand response is high (800 Euro/MWh), its overall impact reduces the system LCOE. The impact of demand response is estimated to be limited but positive due to the limited flexibility of load as described in section 2.2.3.4. The demand response reduces the system LCOE by almost 0.4% with an estimated absolute benefit of 0.15 Euro/MWh, as given in Figure 20.

Figure 20: *Costs and benefits of demand response on the system LCOE in 2026*



4. Comparison of the Flexibility Options

In this section, flexibility options are compared with each other based on their costs and benefits measured in economic terms, and their benefits measured in terms of reduction in redispatch, reserve requirements and curtailment. The section continues with a sensitivity analysis for the costs and benefits of flexibility options and finally, the impact of combining different flexibility options is discussed.

4.1 Comparison of costs and benefits of flexibility options

The range of benefits are grouped within a narrow limit of 0.3-0.5 Euro/MWh. Retrofitting old coal-fired power plants provide the highest value of benefits estimated at around 0.5 Euro/MWh.

Impact of flexibility options on the system LCOE in each case is dependent on the investment and operational costs. Operational costs are already calculated annually; however, investment costs are levelised based on the economic lifetime of the option. Flexibility options that have longer economic lifetimes have advantage. For example, options like pumped-hydro storage that have long lifetime has much less impact on the system LCOE when compared to battery storage systems that have significantly lower lifetimes (see Figure 21). In addition, the cost of operation is also a significant factor especially for batteries where the utilisation also has an impact on the lifetime. From a cost-benefit perspective, options are ranked as follows: demand response, pumped-hydro storage, mechanical CAES storage, high-temperature NaS storage and retrofitting old coal-fired power plants.

4.1.1 Costs and benefits measured in economic terms

The range of benefits are grouped within a narrow limit of 0.3-0.5 Euro/MWh (see Figure 21). Retrofitting old coal-fired power plants provide the highest value of benefits estimated at around 0.5 Euro/MWh. The main reason for the higher benefits offered by this option is the faster response of these units to changes and their increased secondary control reserve capability. Especially, the reserve capability allows the operator to purchase frequency control reserve from more economical sources and thus avoid start-up of gas units and close-down of some thermal units with lower operating cost.

High temperature and Li-ion batteries provide the second highest benefit estimated at around 0.45 Euro/MWh.

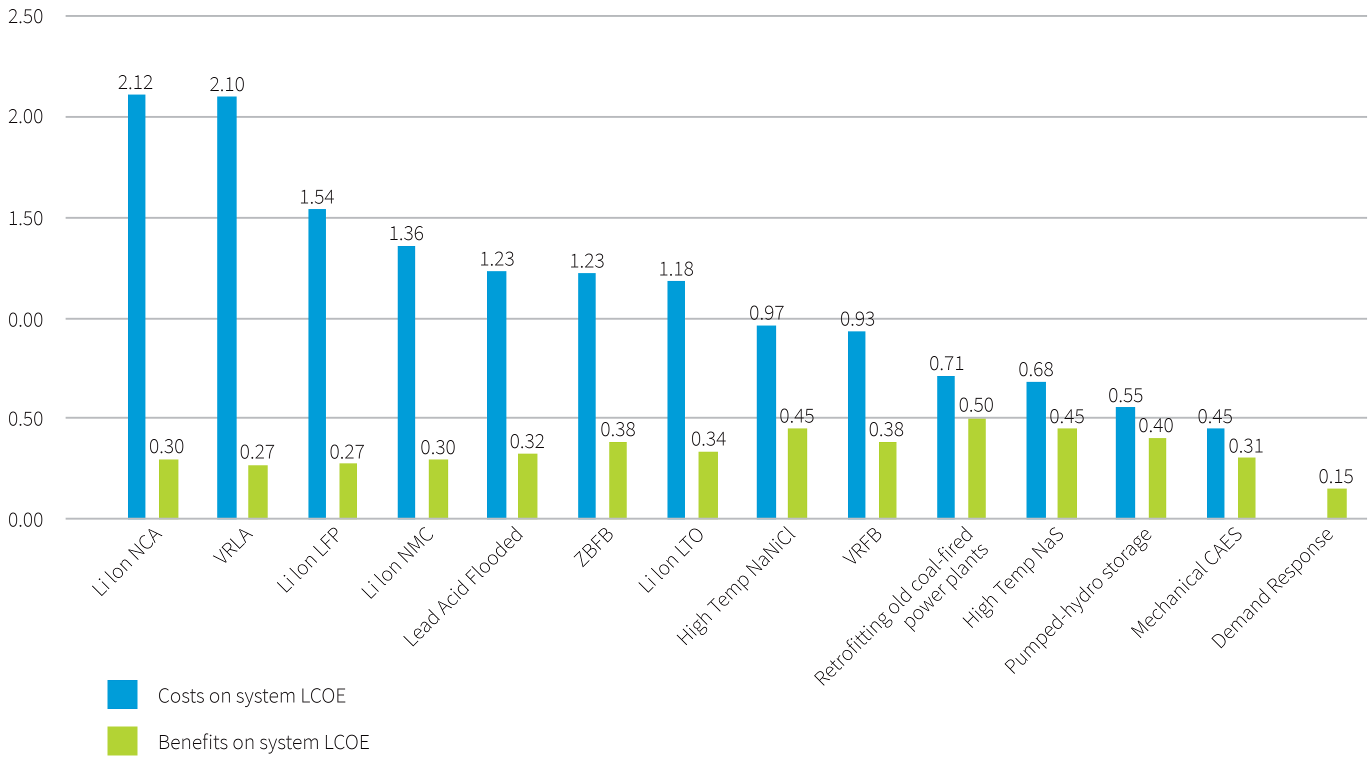
High temperature and Li-ion batteries provide the second highest benefit estimated at around 0.45 Euro/MWh. The main reason behind this figure is the high flexibility of these batteries. They can use almost all energy capacity and the units can go down to very low states of charge. Such flexibility allows these batteries to support the system operator better than other technologies which cannot be fully discharged.

The pumped-hydro storage and flow type batteries have almost equal impact in terms of benefits which were estimated at around 0.4 Euro/MWh. One limitation for the pumped-hydro storage is that it is not distributed among the network but connected at a single point. This limits its effectiveness to an extent. For flow type batteries, in turn, efficiency is the main reason of slightly lower benefits. Since their cycle efficiency is around 70%, these batteries lose 30% of stored energy at each cycle.

Benefits of lead acid and mechanical CAES storage technologies are close to each other at around 0.3 Euro/MWh. Both of these technologies have strong limitations due to their minimum levels of state of charge and cycle efficieny. These limitations are reflected in their performance resulting in a relatively limited impact on benefits. Finally, demand response has the least benefits estimated at around 0.15 Euro/MWh. Demand response is only introduced when all other alternatives are ineffective or more expensive. This is explained by its high activation costs. Moreover, the amount of demand response is limited to 5% of the load in each substation. Despite the fact that 5% of load creates a very large capacity in total, the utilisation is much less due to high utilisation cost of this item, which practically limits its effectiveness at relatively low levels. On the other hand, if its benefits are compared with its costs, this is the best option under the assumptions defined in 2.2.3.4.

Figure 21: *Comparison of the impacts of costs and benefits of each flexibility option on the system LCOE, 2026*

Impact of Costs and Benefits on System LCOE (Euro$_{2016}$/MWh)



The costs and benefits of flexibility options presented here fall within an uncertain range of ±20%.

The costs and benefits of flexibility options presented here fall within an uncertain range of ±20% for the following reasons: (i) despite promising developments, it is highly uncertain how the cost of battery storage will develop, which depends on how the total global capacity will evolve and where reductions will mainly be derived from material science concerning cathodes (which determine energy density, cost and lifetime) and other material use for purposes such as cell connectivity, (ii) the assumption made in this study in relation to demand response is that there is a readily available no-cost potential from the manufacturing industry and with rapid digitalisation of the economy, smart buildings would evolve in the near future, (iii) the cost of pumped-hydro storage depends on the selected terrain, and even terrain details are known to project design, and (iv) there are uncertainties with respect to the technology type, flexibility level and the age of power plants that will be retroffited, and to which extent the proposed flexibility measures can be implemented.

4.1.2 Benefits measured in technical terms

Benefits measured in economic terms were estimated on the basis of technical benefits. Flexibility options reduce redispatch orders that are necessary to maintain secure and reliable operation of the system. Based on the characteristics of various flexibility options, the required volume of redispatch is reduced between 2 TWh and 10 TWh per year in 2026 (see Figure 22). This is equivalent to 8%-35% of the total

Based on the characteristics of various flexibility options, the required volume of redispatch is reduced between 2 TWh and 10 TWh per year in 2026.

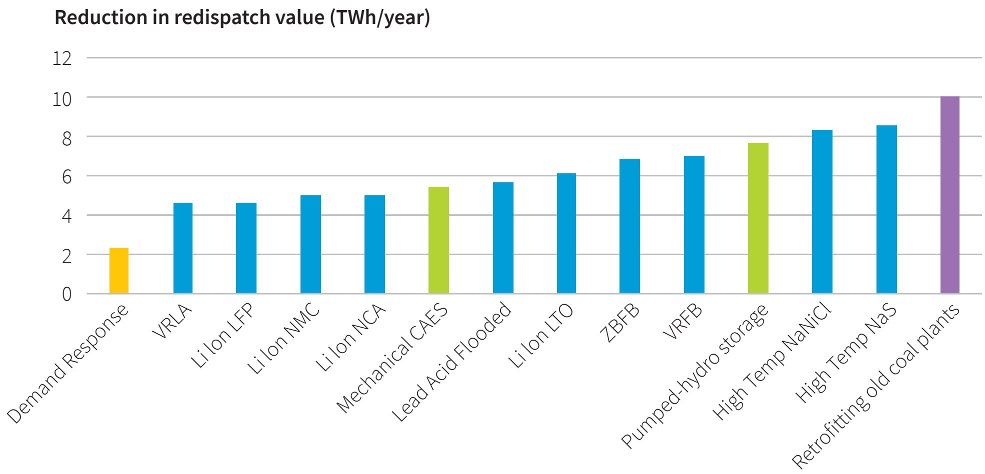
redispatch volume of the Tripling Scenario which provides a total installed capacity of 60 GW of wind and solar PV.

In line with economic benefits, the highest reduction in redispatch is seen in retrofitting old coal-fired power plants. With their new abilities, conventional thermal units have greater flexibility in handling the changes in the network which results in significant reductions in redispatch. Similarly, high temperature battery storage solutions are also able to fill the gap for non-flexible thermal units and they reduce the orders from the dispatcher as in the case of pumped-hydro storage.

At the other end of the scale is the demand response, which has a limited impact. It should be noted that due to the high activation cost of this flexibility option, the algorithm opts for redispatch as a more economic alternative. As mentioned earlier, this option is considered as a last resort and regardless of its activation price, it is a significant tool for the system operator to manage extreme conditions that can occur due to a variety of reasons which are not considered in this study. As opposed to others, demand response is a flexibility option that is expected to be developed regardless of the needs of the power system. The only effort necessary to deploy this flexibility option is to develop the necessary legislations and allow this mechanism to act as individual players or through aggregators in the market structure.

Beyond the regular operation of the power system, which is the main focus of the study on security and reliability, power systems are also expected to maintain their operational abilities under extreme conditions, i.e. their resiliency. Essentially, resilience of any power system is increased with higher rates of flexibility brought by a variety of system benefits. Even though the details of this effect could not be assessed in this study, it is evident that system operators will benefit from fast-responding generation, storage and demand in case of emergency, which would help avoiding brownouts- or blackouts.

Figure 22: *Comparison of reductions in redispatch volume by flexibility option in 2026*



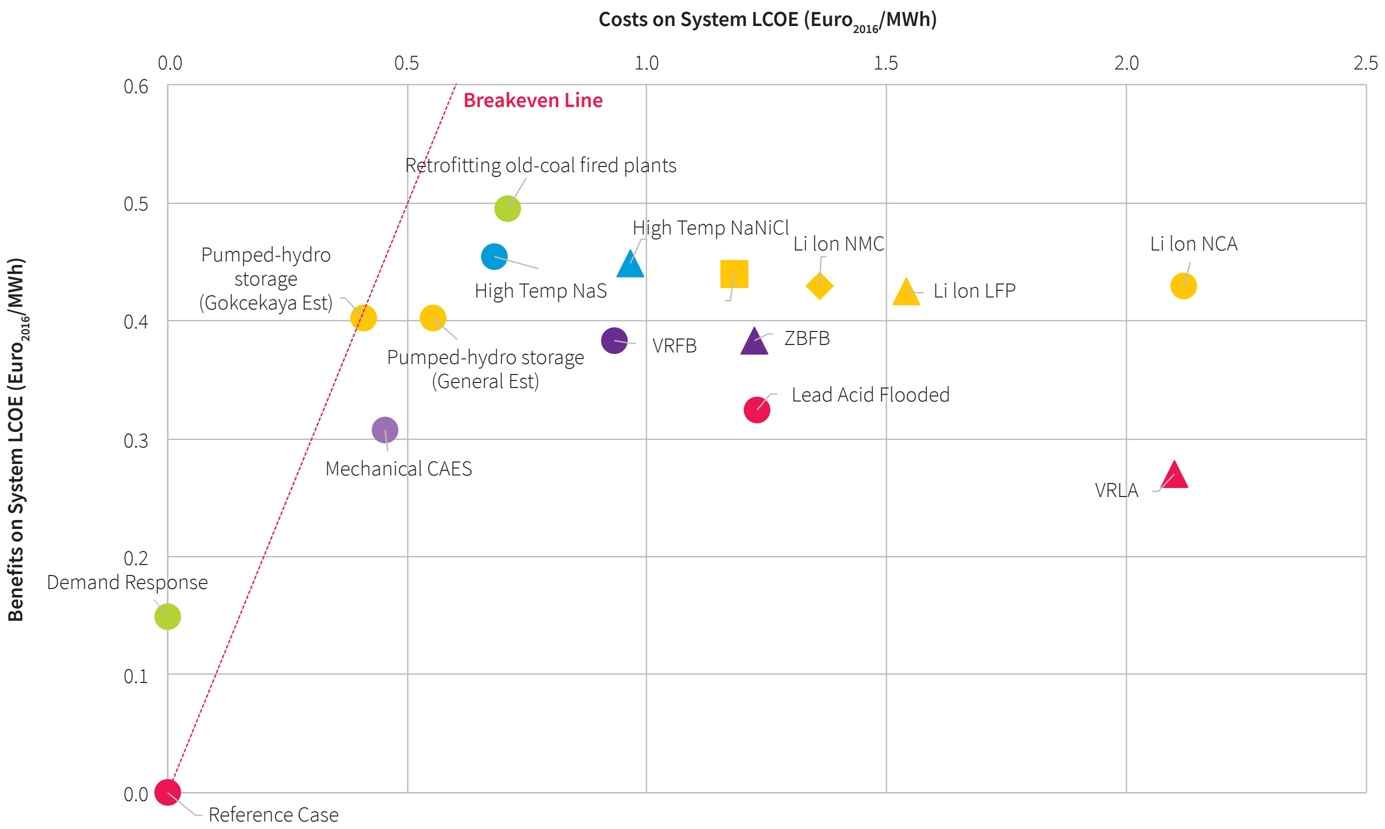
4.2 Most attractive options

Mechanical CAES has relatively low benefits, but due to its long lifetime, the cost impact of this technology is also low, which places it closer to the breakeven line. The only battery storage option that lies close to the breakeven line is the high temperature battery. Retrofitting old coal-fired power plants is the option that lies closest to the breakeven line. Although it has a relatively lower benefit than the options mentioned above, demand response is the only benefit that is available without significant associated investment costs.

The main motive behind any investment is to gain benefits higher than the associated costs. Cost and benefit of each flexibility option is plotted against each other in Figure 23. Most options are below the breakeven line, which means they result in a net increase of costs. Some of these options are relatively close to the breakeven line (constructed on the basis of data points where costs are equal to benefits), which renders them more attractive.

- Mechanical CAES has relatively low benefits, but due to its long lifetime, the cost impact of this technology is also low, which places it closer to the breakeven line. However, no significant study has been made in Turkey so far on this technology to determine potential locations and capacity . Considering available alternatives with higher benefits and current status of the technology in Turkey, it is not expected to be developed and realised within the time horizon of this study.
- Pumped-hydro storage is another promising technology that lies close to the breakeven line. If the investment cost assumption for Gökçekaya plant is adopted following the JICA study instead of the generic value provided in the tool made available by the IRENA, the resulting net impact of the plant would be on the breakeven line, which would render this option an attractive one for the case of Turkey. Pumped-hydro storage, including the one in the Gökçekaya, is under discussion and therefore can be considered as a technically viable option as well.
- The only battery storage option that lies close to the breakeven line is the high temperature battery. These systems have the advantage of utilising 100% of their charge during operation and have relatively longer lifetimes. Hence, they can also be considered as one of the relatively attractive options. Moreover, it should be noted that the benefits of these batteries are almost equal to those of Li-Ion, even though their cost is relatively lower.
- Retrofitting old coal-fired power plants is the option that lies closest to the breakeven line. Although retrofitting may require the allocation of considerably large funds (in the order of 25% of the capital cost), the cost impact is not too high as it increases the lifetime of generators by a minimum of 10 years. Moreover, it enhances the ability of units distributed across the network to handle serious and fast changes in the grid and to provide frequency control reserves. These are important benefits that would be in the interest of the transmission system operator.
- Although it has a relatively lower benefit than the options mentioned above, demand response is the only benefit that is available without significant associated investment costs. With proper legislations, adaptation of the market structure and digitalisation driven by the energy sector as a whole, demand response can become an almost investment-free option.

Figure 23: *Comparison of the costs and benefits of individual flexibility options*



As shown in this analysis, there are several options that can provide flexibility in the market. Each option has its own costs and benefits for the system and the magnitude of benefits brought by reducing curtailment and redispatch differs by technology. None of the options can be considered as a silver bullet or a top priority. It is rather the opposite; a mix of options would need to be in place. To enable this, the right policy framework would be needed to incentivise the flexibility needed in the market. Required mechanisms will be short-term and balancing markets, with clearly defined and transparent rules.

None of the options can be considered as a silver bullet or a top priority. It is rather the opposite; a mix of options would need to be in place. Storage systems are beneficial, but their current cost is still high.

Developing this framework requires a better understanding of the feasibility and realistic time frames concerning these flexibility options besides their costs and benefits. These are discussed below in more detail:

- Storage systems are beneficial, but their current cost is still high. Battery storage systems in various sizes can be purchased from manufacturers around the world and can be realised in relatively short time frames. Furthermore, based on the requirements of the recently cancelled second auction for solar PV, plants have been considered to have large scale (in the order of 10 MW to 50 MW) battery storage installations included in the package. In addition to these large-scale systems, smaller scale applications (even behind-the-meter installations and electric vehicles) can be aggregated to provide services foreseen in this study. Hence, the capacity of battery systems connected to grid (at any voltage level) is expected to increase and with proper control schemes, the existing systems can be adapted to provide the services considered in this study. This may reduce the cost of storage systems and can be significantly beneficial for the power system. Moreover, in addition to the benefits discussed in this study, storage systems can be used for a variety of other tasks like primary frequency control, black start, damping of inter-area oscillations.

The pumped-hydro storage is one of the most attractive options with very long lifetime.

- Mechanical CAES feasibility has not been discussed in Turkey so far. Hence, these projects are not expected to be applied within the time interval of this study unless there is a policy incentive for doing so.
- The pumped-hydro storage is one of the most attractive options with very long lifetime. Considering a long-term vision about the power system with very high penetration levels, pumped-hydro storage can be a strategical decision especially considering that it can allow the integration of further renewables into the system. Pumped-hydro storage was discussed and investigated in 2010 with the support of JICA. Potential application areas were identified and rough cost estimations were made. The discussions further elaborated the decisions on nuclear power plants. Even though there is not any active construction or a new project under discussion currently, this is a topic that the private sector also keeps an eye on. During stakeholder meetings of SHURA's grid integration study (Godron et al., 2018), one of the discussion topics with the private sector was the favourable potential of pumped-hydro storage. Undoubtedly, these large investments require significant funding and support from the government, which may build up as the share of renewable energy increases. In this study, only Gökçekaya is considered as an option. However, there can be many other places where this technology can be applied at different scales.

Considering its benefits along with the extension of the technical lifetime of units, there may be a way for thermal plants to continue their businesses in an energy system with higher shares of renewables while providing benefits to the system.

- As described in section 3.1, increase in renewables results in a significant drop in thermal generation. This reduction is expected to influence thermal generation businesses significantly, causing permanent shutdown of power plants. In such an environment, increasing the flexibility is a new means to become more competitive in the market. Considering its benefits along with the extension of the technical lifetime of units, there may be a way for thermal plants to continue their businesses in an energy system with higher shares of renewables while providing benefits to the system. Retrofitting old coal-fired power plants requires a detailed investigation and feasibility study on a plant by plant basis. As mentioned previously, examples of very flexible units running on lignite with qualities similar to some plants in Turkey are available, but this does not readily imply that the technology can be adopted for all existing plants in Turkey. In fact, such decision should be made specifically for each case. On the other hand, even though a large part of coal-fired power plants is older than 20 to 30 years, most of them can be retrofitted to improve the flexibility, increase the lifetime and decrease maintenance costs. Such investment can be realised in a period of about half a year to two years, depending on the feasibility of the retrofit and available funding.

Demand response can be considered as a starting point given its almost investment-free availability and the readily available potential offered by the industry.

- For instance, demand response can be considered as a starting point given its almost investment-free availability and the readily available potential offered by the industry. Demand response, as of today, can be realised by large-scale electricity-intensive sectors such as steel or cement industries. These industries are already equipped with the necessary infrastructure including smart meters. Also, the current legislation considers demand response as part of the balancing mechanism. Energy planners aim to develop new legislations on demand response by positioning it as an ancillary service. The draft legislation is expected to be finalised in 2019 and a pilot application is targeted for 2020.[12] Hence, demand response is expected to be adapted in the near future as an ancillary and/or balancing service.

[12] Stakeholder meeting conclusions of "Talep Ve Dağıtık Üretim Kaynaklarının Birleştiriciler Üzerinden Piyasaya Katılımı Sonrası İhtiyaç Duyulacak Olan Piyasa Mekanizmalarına ve Kurumlar Arası Koordinasyona Yönelik Araştırma ve Öneri Geliştirme Projesi" coordinated by AKEDAŞ, supported by the Enerji Piyasası Denetleme Kurulu (EPDK), Feb 2019.

4.3 Sensitivity analysis

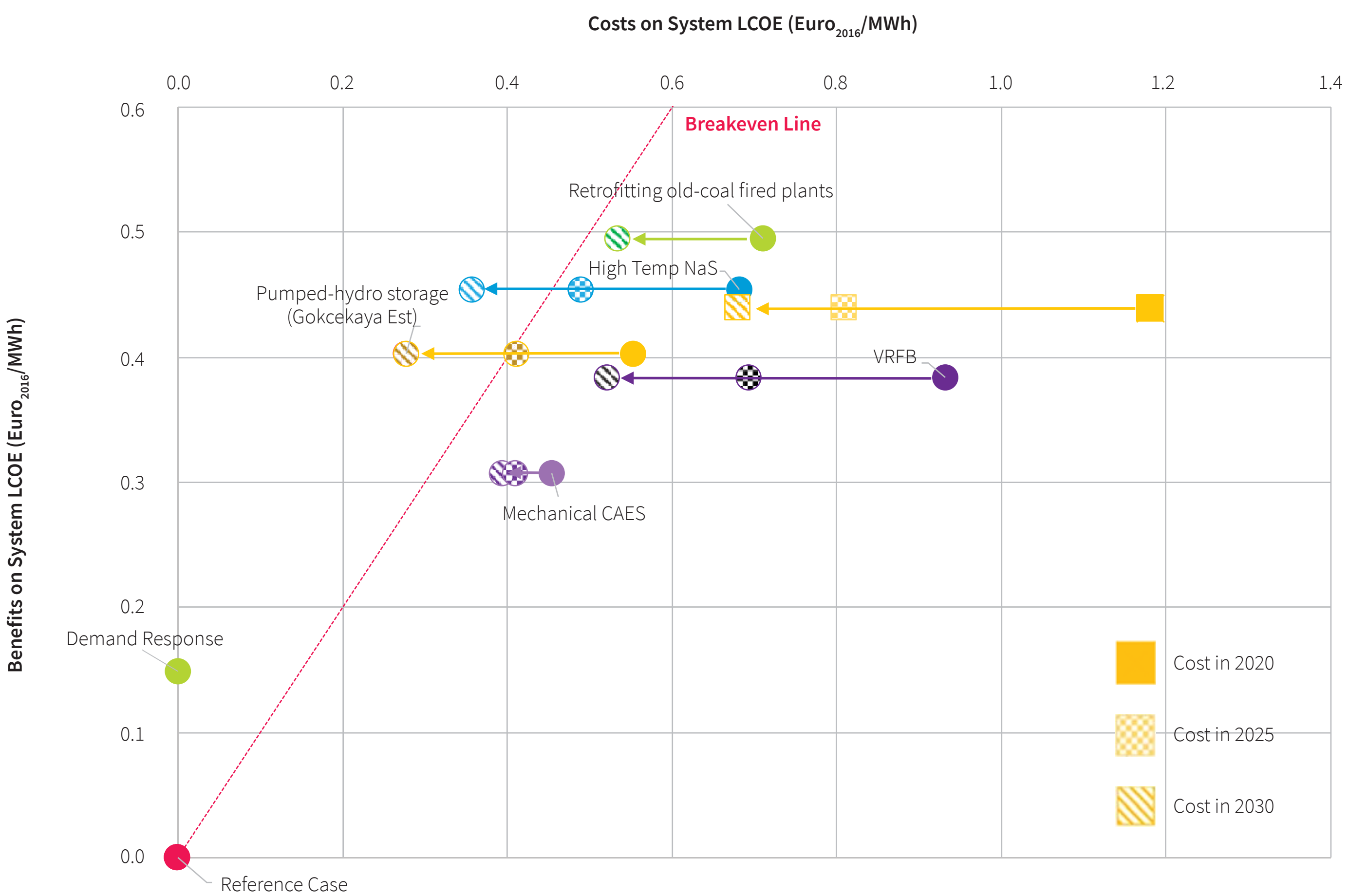
Cost effectiveness of the flexibility options is mainly determined by the investment cost. While battery systems are expensive, all other alternatives also require significant investment and operation costs (except demand response, which is considered to have a high activation cost only). Technological learning would reduce these costs as more capacity is installed worldwide (IRENA, 2017). Benefits, on the other hand, would become more evident as the share of renewables increases. To address these two aspects, a sensitivity analysis was carried out.

For almost all storage systems, the costs decline significantly when a further reduction in the costs of battery systems compared to today's level is assumed.

4.3.1 Sensitivity to the cost reduction in the flexibility option

Given the uncertainty in technology development across the time horizon foreseen in this study and the underlying assumptions for the assessment of the costs and benefits of technologies, a sensitivity analysis was performed. The investment and operation costs of storage systems were recalculated in view of IRENA's 2025 and 2030 cost projections, which are presented in Figure 24. For almost all storage systems, the costs decline significantly when a further reduction in the costs of battery systems compared to today's level is assumed. By comparison, retrofitting old coal-fired power plants shows a relatively small decrease. The benefits from storage systems remain unchanged, because these devices were considered as zero-cost options in simulations. Pumped-hydro storage and high temperature batteries move to the left of breakeven line, which means that they become cost-effective as their costs fall to levels expected to prevail by 2025 and 2030. On the other hand, specific projects may be realised with lower costs than predicted in these general calculations.

Figure 24: *Sensitivity analysis for energy storage system costs*



The need for redispatch is much lower in integrating a 21% share of wind and solar power than integrating a 30% share. As the redispatch requirement decreases at each hour, the cost of redispatch for a particular hour also declines since the algorithm chooses the most cost-effective redispatch option first. This difference creates a nonlinear reduction in the cost of redispatch at each hour. Therefore, the benefits from managing these redispatches by flexibility options are also lower.

4.3.2 Sensitivity to the renewable penetration level

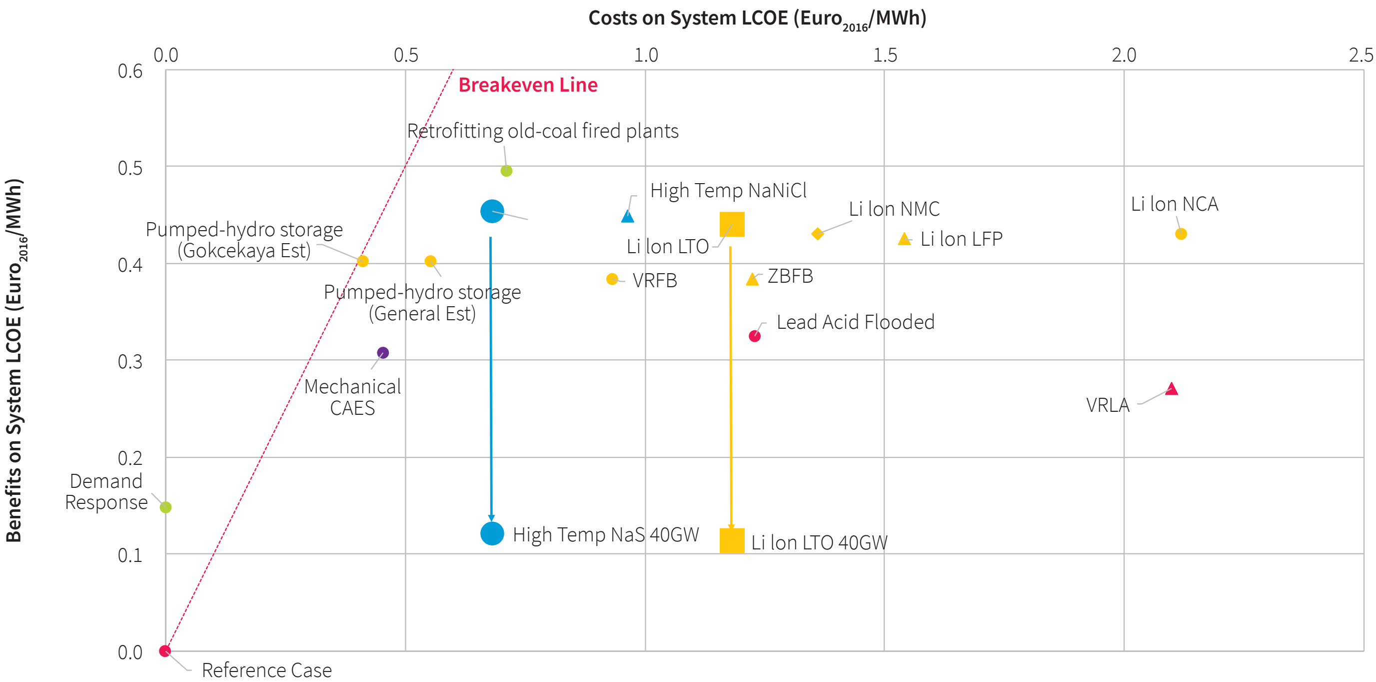
The major outcome of SHURA's grid integration study (Godron et al., 2018) was that the challenges to operate the power system in a secure and reliable manner becomes increasingly difficult as the total installed wind and solar capacity increases from a total of 40 GW to 60 GW in 2026. This implies an increase in variable renewable energy share in total generation from 21% to 30%. Hence, flexibility options have a crucial role in the grid integration of renewables. The question is whether flexibility options are equally important to accommodate a lower share of variable renewable energy share. This is especially important since there is a significant industry and policy focus on the development of these technologies in Turkey even though solar and wind energy currently has a share in total electricity demand just below 10%. To address this question, two battery systems (NaS and Li-ion LTO) were evaluated for the case of integrating 40 GW of wind and solar capacity, which would supply 21% of Turkey's total electricity demand in 2026.

Without the need for any flexibility option, a power system with 40 GW of wind and solar PV capacity can be operated under conditions that are similar to the level in 2016:

- The redispatch level is in the order of 5.3% of the annual demand. This compares to the level in 2016 when redispatch level was just below 5%,
- no curtailment of electricity from wind and solar is necessary, and
- no additional investments are needed in transmission grids compared to TEİAŞ's Ten-Year Network Development Plan.

The need for redispatch is much lower in integrating a 21% share of wind and solar power than integrating a 30% share. As the redispatch requirement decreases at each hour, the cost of redispatch for a particular hour also declines since the algorithm chooses the most cost-effective redispatch option first. This difference creates a nonlinear reduction in the cost of redispatch at each hour. Therefore, the benefits from managing these redispatches by flexibility options are also lower. The results of the simulation are shown in Figure 25 in which the benefits associated with storage systems are significantly lower. This outcome indicates that the benefits from flexibility options follow a nonlinear relationship with the share of wind and solar.

Figure 25: *Sensitivity analysis for lower shares of wind and solar*



4.4 Impact of combining different flexibility options

The power exchange market outcomes present the optimum solution for the operation of the power system. Due to operational requirements, the security and the reliability of the power system, the system operator is forced to perform redispatch and/or curtailment. The SRMC was estimated taking the effect of these factors into account. For the Tripling Scenario, the weighted average SRMC was estimated at 37.85 Euro/MWh. However, when the power exchange market solution is taken as a reference, a lower estimate of 35.60 Euro/MWh is made for the weighted average SRMC of the capacity mix. The 2.26 Euro/MWh difference between these estimates is the cost of keeping the network operable, secure and reliable.

Essentially, all flexibility options are utilised in order to ensure a secure and reliable operation of the grid and to reduce the cost difference between the power exchange market outcome (the optimum operation point) and the secure and reliable operation point (after order of the operator). Based on their position on the network topology and capabilities, each flexibility option provides a solution for a different subset of the problem set. Unfortunately, these subsets of problems solved by each flexibility option intersect with each other. Accordingly, the benefit from activating multiple flexibility options at once is always less than the sum of benefits from individual flexibility options. As more flexibility options are included in the system, the benefits would certainly increase, but this will be so with a saturating characteristic, especially when the operation point gets closer to the power exchange market solution.

On the other hand, the costs increase as a sum of individual costs. Therefore, multiple flexibility options employed together would result in an additional cost equal to the sum of individual costs, whereas the benefit from these options would be less than the sum of individual benefits.[13] Hence, before combining different options, this saturation effect should also be taken into consideration for a proper valuation of investments. Essentially, when combining different flexibility options, the cost impacts of different options accumulate whereas benefits are expected to saturate. In other words, if two flexibility options are applied simultaneously, the total cost of the combination will simply be the sum of the costs of these options. On the other hand, the sum of their benefits will only form a theoretical upper band for the benefit, which is highly unlikely to be achieved. In practice, the combined benefits saturate to a lower benefit than the sum of two separate options. In order to assess the impact of costs associated with individual flexibility options and their benefits, which are defined in this study as the reduction in annual average cost of energy, a series of calculations and simulations are carried out.

Beyond the regular operation of the power system, which is the main focus of the study on security and reliability, power systems are also expected to maintain their operational abilities under extreme conditions refered to as resiliency.

Beyond the regular operation of the power system, which is the main focus of the study on security and reliability, power systems are also expected to maintain their operational abilities under extreme conditions refered to as resiliency. Essentially, resilience of any power system is increased with higher rates of flexibility of a variety of system benefits. While these factors could not be assessed in this study, it is evident that in emergency situations system operators will benefit from fast-responding generation, storage and demand, which will help avoid brownouts and blackouts. A more renewable and flexible power system also has certain macroeconomic benefits, which are not quantified here. One clear example of such benefits is the reduced

[13] It should be mentioned that benefits to be derived from local and small applications of flexibility options may be potentially equal to sum of individual benefits, but this is not the case for network scale applications.

demand for imported gas, which is a crucial issue in Turkey's energy policy priorities. Compared to the Base Case, the Tripling Scenario with flexibility options would save around 30 TWh of electricity generated from natural gas by 2026, resulting in a total gas-based electricity output of 37 TWh. This is around one-third of the current total electricity output from natural gas. The benefits gained from flexibility options, notably energy storage, are around 10 TWh since gas is no longer needed to supply reserve requirements and system flexibility. Therefore, increasing the share of wind and solar energy from 12% in the Base Case to 30% in the Tripling Scenario, and increasing system flexibility could save around 7.5 billion cubic meters of imported gas each year, an amount equivalent to an economic benefit of 1.5-3 billion Euros annually. Another major macroeconomic benefit of renewable energy and locally manufactured flexibility equipment such as battery storage would be the creation of new jobs. Today, around 85,000 people are working directly and indirectly in the renewable energy sector (excluding large hydropower plants). By 2026, this figure will be higher as installed electricity generation capacity and the capacity for flexibility will grow with higher levels of economic activity ensured through policy mechanisms that support local content. Therefore, it is also important to consider these benefits in designing strategies and policies for transition to a low-carbon energy system in Turkey.

5. Policy Recommendations

Increasing the flexibility of Turkish power system beyond the existing level, which mainly relies on hydropower and gas-fired power plants currently, may reduce transmission investments and electricity prices while increasing system reliability, which would provide benefits that would outweigh cost, particularly at high shares of wind and solar. In order to facilitate grid integration and incentivise investment in flexibility options and operation, the following steps are suggested:

1. **Develop a comprehensive grid integration plan for wind and solar based on a geographically elaborated strategy to balance supply and demand and by increasing system flexibility:** To integrate 60 GW of wind and solar PV capacity by 2026, Turkish power system needs to be more flexible. As the results of this study show, there is no silver bullet for any flexibility option. Each option has its own costs and benefits and ease of implementation that will limit the extent it can be deployed. A portfolio of options will be needed, including demand response, retrofitting of old and inflexible coal-fired power plants and energy storage. Each option can be implemented at a different point in time and each will yield different magnitudes of benefits and costs. Taking these factors into account, a deployment plan with a timeline should be developed now in line with the rapid growth in wind and solar PV capacity deployment.

2. **Create a regulatory framework and develop supporting policy mechanisms that reflect the value of flexibility to provide adequate incentives for making use of available flexibility options and investing in new ones. In this respect, the essential instruments are transparent short-term and balancing markets:** Currently, there is no clear regulatory framework that provides adequate incentives for the system-wide integration of wind and solar capacity while increasing system flexibility. In order to complement the proposed strategy in this analysis, it will be necessary to deploy different flexibility options, new policy mechanisms and new financing options, when necessary, so as to reduce the impacts of grid integration of renewable energy on system costs. More precisely, short-term and balancing markets should be introduced to make sure that different flexibility options in technology and scale will be competing on a level playing field, as a diverse set of options will drive down the cost of flexibility and increase reliability. In designing such mechanisms, it will also be important to consider the broader macroeconomic benefits of a flexible power system with higher shares of renewables such as a better trade balance, new economic activity and new employment.

3. **Implement early opportunities with low cost which can provide rapid response ability for increasing system flexibility requirements:** Pumped-hydro storage have a long track record, and capacity can be deployed as an attractive option in several suitable locations in Turkey, including Gökçekaya plant assessed in this study. Considering a long-term vision about the power system with increasing levels of wind and solar energy over time, pumped-hydro storage can be a strategically beneficial decision for the power system. Likewise, retrofitting of suitable coal-fired power plants may be initiated today for capacity building where it makes most sense; in other words, by taking the type of coal used, age and efficiency of plants, and the share of coal use into account in view of Turkey's climate policy targets.

4. **Identify and overcome barriers related to demand response given its attractiveness:** Since demand response is almost an investment-free option, it should be considered as the starting point. However, the activation of demand response needs to be coupled with efforts in managing electricity load in buildings and industry. A more holistic approach of the energy system based on sectoral integration policies will be crucial in utilising demand response as a flexibility option. Industrial load in Turkey offers an immediate potential as the load in steel and cement plants can be shifted easier than the load in buildings. Achieving demand response in buildings will require the use of more sophisticated tools and additional investments for smart grid infrastructure, like smart meters, sensors and control systems, and digital connections. In addition, new mechanisms for consumer participation will prove beneficial.

5. **Develop a plan for battery storage by analysing its value and role for different technologies at stages of higher wind and solar shares in detail:** Battery storage systems are beneficial, but the initial capital costs of most technologies are still too high compared to the benefits they would bring to the systems. Thus, it will be necessary to plan the required storage capacity with wind and solar capacity in order to minimise additional system costs and to derive the most benefits where needed. One possible way forward for the deployment of these systems is to start with smaller-scale installations, provide niche services where batteries can perform other applications with more attractive benefits and complement other flexibility options. Furthermore, systems installed for different tasks (electric vehicles, behind the meter installations, low and medium level voltage installations, industrial applications, etc.) may partially, between certain time intervals or fully assume the tasks considered in this study either via aggregator companies or individually. Obviously, such an application requires communication infrastructure, protocols and legislations, but studies regarding all these elements can be launched today to be ready for future needs.

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